TDV Cookbook Appendices
Input Data Sources

List of Appendices

Electricity Wholesale Cost Forecast Background

The California Energy Commission forecast developed by the Electricity Analysis and the Demand Analysis Office provides the long-run wholesale and retail rate forecasts used in the development of the TDV values for electricity in the years 2005 through 2034 as referenced below. The detailed forecasting methodology can be found in the "2002-2012 Electricity Outlook Report", published by the California Energy Commission in February 2002. This Outlook Report describes the methods and data used to develop the CEC forecast only through 2012.

In the years 2013-2021, the following assumptions were made to further develop the forecasts:

- Reduction in Department of Water Resources (DWR) purchase volumes
- Expiration of DWR contracts
- Removal of financing payments for DWR electricity contracts
- Changing spot market prices from the "low reserve margin" price scenario to the "long-run equilibrium" price scenario
- Removal of investor-owned utility (IOU) debt financing payments

Finally, the wholesale electricity costs were extrapolated out from 2022 to 2034. The non-generation costs were extrapolated based on the previous five years whereas the generation costs were extrapolated at the same rate of increase in natural gas costs during 2022 through 2034.

The forecasts of wholesale energy costs were developed for PG&E, SCE, and SDG&E. This forecast incorporates information on DWR long-term contracts, forecasted fuel prices, generation mix, and the long-run cost to build and operate a combined cycle gas turbine (CCGT).

The forecasts use the May 2001 reported current and future levels of the DWR contracts through 2012. In 2012, the DWR contracts are assumed to be reduced by 65% and eliminated completely from the forecasts in 2015. To determine how much DWR load is allocated to each utility, the total DWR load volume is split between the three utilities using a weighting factor based upon the CPUC determination of DWR contract costs and allocation for the years 2001 and 2002 in the Draft PUC decision *A.00-11-038*.

The current IOU debt financing assumptions, which are included in the forecast model, reflect a 15-year financing period with a finance rate of 7.25%. The debt levels embedded in this forecast are $700 million for SDG&E, $2.2 billion for SCE, and $3.2 billion for PG&E.

Electricity Retail Rate Forecast
Once the weighted average T&D and generation costs are calculated, a revenue neutrality adder is estimated so that the load weighted average of the T&D, generation, and revenue neutrality adder results in forecast retail rates for each class.

In the years 2005 through 2012, the CEC developed the annual retail prices which reflect the "Low Reserve Margin Scenario" in the 2002-2012 Electricity Outlook Report, as described in the wholesale electricity cost section above. Beyond the 2012 forecasts described in the Outlook Report, 2013 through 2021 costs also incorporate the following assumptions:

- Reduction in DWR purchase volumes
- Expiration of DWR contracts
- Removal of financing payments for DWR electricity contracts
- Changing spot market prices changed from the "low reserve margin" price scenario to the "long-run equilibrium" price scenario
- Removal of investor-owned utility debt financing payments.

As described previously, the 2022 through 2034 retail forecasts were then extrapolated to years 2022 through 2035. The non-generation costs were extrapolated based on the trend for the previous five years. The generation costs were extrapolated at the same relative rate of increase in natural gas costs from years 2022 through 2035.

Average retail rates were then separately calculated for residential and nonresidential buildings based on the most commonly used residential and large commercial customer tariff classes for each utility; residential, small commercial, medium commercial, industrial, and agricultural. The customer tariff classes for the utilities are:

	PG&E	SCE	SDG&E
Residential	E1	D	RES
Non-Residential	A10	GS-2	MED C/I <500 kW

This forecast was based on the current simple average rates for each major customer class for non-generation costs, and the forecasted wholesale costs for each IOU as described in the previous section. Finally, the total annual average costs were adjusted to assure revenue neutrality for each IOU.

Valuation of Environmental Externalities from Electricity Generation

Introduction

E3 has examined the most appropriate CEC proceedings in which the current environmental adder was reviewed and established. Based on the evidence that the CEC does not endorse its own previously-published (ER94) approach to environmental adders, E3 has investigated methods independent of, rather than incremental to, the CEC approach. This report summarizes E3's findings on these methods and their implications for valuing environmental externalities in the California electricity market.

This report looks at how best to structure and value environmental externalities based on a] market costs as experienced in emissions trading, and b] emissions abatement costs. The report is structured to consider the various approaches one could take in valuing externalities. We begin by identifying the key variables to concentrate on valuing, i.e., those that have the greatest impact on overall externality valuations. Once the overall approach and specific externalities have been identified, we assess how NOx emission trading and emission reduction costs have been valued over time, along with identifying some of the issues arising from the recent NOx market activity. Next, we tackle the issue of how to best value CO_2, the other key externality within the California market. The report closes with recommendations for estimating more stable and precise externality values for the key emissions, and it suggests a central range of overall externality costs.

Background

Under the most recent Warren Alquist Act revisions, the CEC is still required to "include a value for any costs and benefits to the environment" in estimating the cost-effectiveness of energy resources and programs. However, there has not been an official CEC proceeding or decision on the topic of valuing environmental externalities and adders since the Electricity Report of 1994 (ER94). While senior CEC staff concur that there is still a need to consider environmental costs and benefits (consistent with the Warren Alquist Act), there is little confidence in the externality values that were calculated for ER94 or other documents. One senior staff member indicated that the present staff attitude is to "not endorse the use of any externality number for any purpose."

Among CEC staff, there is general skepticism regarding the estimation of externality values on the basis of environmental damage functions (see Appendix 1 for an overview explanation of potential externality value-estimation methods). Although using environmental damage functions best represents the theoretically correct economics, it is seen as having less practical value than simpler approaches based on mitigation costs, emission allowance market prices, etc. (See the following section and Appendix 1).

This rather significant distancing from the idea of quantifying the value of environmental externalities is further complicated by the inclusion of such valuations, however simplistically, in PG&E's PY2000 Annual Earnings Assessment Proceeding filing. The economic valuation input assumptions shown in Table TA 1.1 of Volume III of this filing were approved by the CBEE and show $/MWh values through the year 2023, including environmental externality values.

Meanwhile, other states have enacted legislation or regulations calling for the consideration of environmental externalities in electricity planning, and several (Massachusetts, Minnesota, Nevada, New York, Oregon) have assigned values to certain categories of emissions. The values are generally in the same order of magnitude as those for California (see Table 2 below). These externality values are generally based on marginal control costs, and they are used for indicative purposes only. Massachusetts began to require the direct application of externality values in electricity resources decisions, but this measure was successfully challenged and finally overturned by the Massachusetts Supreme Court.

Thus, there are continuing academic debates, political controversies and legal complications surrounding the issue of environmental externality valuation, as well as a severe lack of convincing empirical data to resolve the issue. It is clear that a simple, practical approach is needed, at least in the interim until greater scientific and political consensus is reached to resolve some of these controversies and uncertainties. To flesh out the positions of various stakeholders in the environmental externalities debate, the following practitioner and academic resources were tapped for input to our analysis:

- LBNL and university researchers who have historically contributed to the externality discussions in the past [for methodology and data sources]
- Emission trading brokers that make markets in a) national SO2 emission allowances, b) RECLAIM (Regional Clean Air Incentive Market) credits under the South Coast AQMD, etc. [for market prices]
- CEC 1999 Electricity Generation Emissions Report [for current siting regulations]
- California Air Resources Board web site [for current emission standards, inventories and compliance levels]
- The World Bank and their Prototype Carbon Fund [for CO_2 trading activities]
- The US EPA web site regarding various emission trading programs [for market structure and history]
- US EPA reports on past and future benefits of the Clean Air Act [for calculated damage values assigned to different air pollutants]
- DOE/EIA case studies for valuing externalities in different states [for a comparison of methods and results]
- Reports from the European Union project "ExternE" on externalities [for methodology and results of damage valuation studies]

Overall Approach to Environmental Externality Values and Adders

Summary: The most practical approaches presently available for valuing environmental externalities and adders involve the estimation of marginal emission reduction costs and the observation of market clearing prices in emission trading markets.

There are several basic approaches to valuing externalities (see Appendix 1):

- Qualitative and ranking approaches
- Estimation of marginal emission reduction costs
- Observation of market clearing prices in emission trading markets
- Estimation of marginal damage costs (at present or optimal state)
- Willingness-to-pay analysis (survey methods, contingent valuation)

Of these, the first, qualitative and ranking approaches, is not very useful in estimating adders, since the adders by their very nature, need to be quantitative indicators. At the other end of the spectrum, damage costs and willingness-to-pay analyses are very difficult to apply in practice. The latter methods are controversial, data intensive and computationally complex, none of which sound very appealing from an implementation perspective. Moreover, the many assumptions implicit in these methods can lead to results that vary by as much as an order of magnitude, even after intensive analysis.

Therefore, E3 recommends focusing on the two remaining and related methods to estimate environmental adders that have been designed to capture the external benefits of energy-efficiency measures and programs. These two approaches focus on a) marginal emission reduction costs (MERC) and b) emission trading market-clearing prices.

These methods share a common assumption, being that the current level of legislated/ regulated emission compliance is based on a societal consensus, which equates to an assumed efficient (and acceptable) degree of emission reduction. Although regulated emission levels are political decisions having little linkage to economically optimized reductions, these criteria are easily observable once emission controls or trading markets are in place.

These two methods are also related, at least in theory, by the fact that MERC drives both the supply and demand aspects of emission reduction offsets and credits in the market. Theoretically, at a given price threshold for emission credits, a firm should ideally implement emission reductions that cost less than the credit price, while concurrently buying offsets or credits for any remaining emissions. Conversely, a firm that can reduce emissions at a cost less than the threshold price should do so in order to profit by selling its excess emission credits.

At each price threshold for emission credits, the sum of all the incremental emission "demand," (i.e., firms that have excess emissions that cannot be reduced further at the given price), and the incremental emission credit "supply," (i.e., firms that can generate excess credits from additional reductions), define the demand and supply curves for emission offsets and credits. In theory, the intersection of these curves defines the price at which credits should be exchanged under market equilibrium. Of course, this scenario ignores many real-world limitations, such as transaction costs, imperfect market information, barriers to entry and exit, market power and strategic behavior. But at least conceptually, the observed market trading prices for emission credits should reflect to some degree the marginal costs of emission reductions for participants in that market.

Selection of Relevant Environmental Impacts and Pollutants

Summary: For thermal plants, the most significant environmental impacts and externalities are associated with air pollution emissions. The pollutant species that are most impactful in terms of valuing externalities in California are NOx and CO_2. One should monitor changes in the regulatory or market action regarding PM-10 (and PM-2.5) as well as out-of-state SO_2 sources. E3 does not expect VOCs (ROGs), CO or other species to be significant in terms of relative emissions.

Limit Scope to Impactful Emissions. An essential decision in designing a method to value environmental externalities is to identify the types of environmental impacts and the specific emissions, effluents or other parameters to use as indices of the electric generation's environmental implications. Power generation and transmission have been linked to several types of air and water pollution, land degradation as well as nuclear and electromagnetic radiation. Ideally, an environmental adder or externality value (or series of values) should capture all of these likely impacts through some heady computational design involving realistic weightings across the various environmental implications. However, given the complexity inherent in such an exercise, the effort would be beyond the realm of reasonable implementation expectations. Therefore, one needs to prioritize and focus on the subset of possible impacts that have the dominant impacts.

Assume Gas-fired Generation is on the Margin. Although California has the most diverse set of generating sources in the country, it is anticipated that the marginal generation source in any future California-based scenario will be gas-fired thermal plant. While much of the state's electricity supply comes from hydro and nuclear sources, it is unlikely that an increase or change in energy-efficiency activities would influence the amount of energy generated from these sources. Because these sources have relatively low variable costs, they are essentially "must run" resources that are baseloaded as much as allowed by technical limits, rather than being dispatched (like a thermal plant) on an economic basis.

It is also clear that the preponderance of generation plant being proposed for California is expected to be gas-fired. It is less clear whether out of state generation, particularly coal-fired, would be the marginal plant for any significant amount of time in the future. Absent better information, for purposes of this discussion, this analysis assumes that the environmental impact of new energy-efficiency programs will be realized in the form of reduced emissions from thermal plants using natural gas as their primary fuel. If updated information indicates a preponderance of other primary fuels at the margin (such as coal, diesel or a mix of generation more representative of the Pacific Northwest), then the environmental costs of those units can be incorporated accordingly.

Concentrate on Air Emissions. Bearing in mind the assumption of thermal plants being on the margin, the principal environmental impacts and resulting externalities are air pollution emissions. While land-use impacts are more important for hydro plants, and radioactive exposure and waste more important for nuclear plants, these impacts are much less significant for thermal units. Previous studies of environmental externalities have consistently found that air emissions are the dominant externality values calculated for thermal generation power systems.[1] Hence, the concentration on air emissions.

The principal air emissions can be defined as the Federally regulated "criteria pollutants:" SO_2, NOx, CO, PM-10, ozone, lead and "air toxics." Note that this list should be expanded to include CO_2, the principal greenhouse gas (GHG) responsible for the threat of global climate change.

Although the U.S. has signed (but not yet ratified) the 1997 Kyoto Protocol to the U.N. Framework Convention on Climate Change, CO_2 is not yet regulated at the Federal level. Compliance with the Kyoto Protocol commitments (a 7% reduction in U.S. GHG emissions from 1990 by the first "commitment period" 2008-2012) would, however, require significant policy measures and technological changes to be implemented. This level of emission reductions, or even a less stringent compromise level, would involve significant costs to electricity producers and consumers.

Already, many utilities and other large industrial CO_2 emitters are studying emission reduction opportunities, implementing and documenting low-cost reductions, entering the nascent GHG-emission offset market, and otherwise positioning themselves to manage the costs and risks involved in potential GHG emission limits. It seems likely that management of CO_2 and other GHGs will be the dominant environmental regulation issue during the next 10-20 years. Compliance with the Kyoto Protocol or other national and international commitments will drive the debate over and level of, environmental costs in the electricity industry during this time. Thus, CO_2 should be included in externality valuation analysis.

<u>Focus on NOx and Carbon Dioxide</u>. Of the criteria pollutants, SO_2, NOx, CO and PM-10 can represent significant emissions from thermal power plants. Ozone has been excluded from this analysis because it is not a direct pollutant as such, but rather an indirect pollutant, formed mostly as a result of emissions of other criteria pollutants including NOx and volatile organic compounds (VOCs, also known as ROGs, reactive organic gases). Lead and "air toxics" are also excluded because electricity generation is not a significant source of these species. Thus, the externality values resulting from considering these pollutants is certain to be negligible relative to the more dominant criteria pollutants and would only serve to complicate the analysis. Therefore, ozone, lead and air toxics are excluded leaving SO_2, NOx, CO, PM-10, VOCs, and CO_2 as the relevant pollutant species to assess.

---

[1] See, for example, Pace Univ. Center for Environmental Legal Studies, *Environmental Costs of Electricity*, Oceana Press, New York, 1990; Electric Power Research Institute (EPRI), *Environmental Externalities: An Overview of Theory and Practice*, EPRI CU/EN-7294, EPRI, Palo Alto, CA, 1991; National Renewable Energy Laboratory (NREL), *Issues and Methods in Incorporating Environmental Externalities into the Integrated Resource Planning Process*, NREL TP-461-6684, NREL, Golden, CO, 1994; U.S. Dept. of Energy, *Electricity Generation and Environmental Externalities: Case Studies*, DOE/EIA-0598, DOE Energy Information Agency, Washington, 1995.

Of these pollutants, California's power plants only emit a significant share of the total emission quantity in relation to CO_2 (16%) and NOx (3%). For the other pollutants, more than 99% of their respective emissions are from other sources, such as motor vehicles.

Coal-fired power plants are typically a major source of SO_2, accounting for about two-thirds of the nation's emissions. However, California has no coal-fired stations, and recent regulatory changes have nearly eliminated the use of oil[2] as a generation fuel within the state. Moreover, the out-of-state coal-fired generation sources that supply some of California's demand are not subject to the EPA's emission cap-and trade program, under which generators in the eastern states must operate.

With regard to PM-10 emissions, power plants are not presently an important source. However, with the expected increase in reliance on combined-cycle gas turbines (CCGTs) for baseload power will come increased particulate emissions, even as CCGTs reduce most every other type of emissions, including NOx and CO_2. In addition, proposed new EPA regulations will focus on smaller particulates, i.e., PM-2.5, rather than PM-10. Because PM-2.5 material can be formed indirectly through reactions involving other pollutants, indirect emission of particulates is expected to become more important.

Earlier studies[3] of externality values for California and other states were mostly completed before the onset of the industry's restructuring and deregulation. These produced values that would be insignificant (less than $0.01/MWh) for all pollutant species except NOx and CO_2, using emission factors typical of gas-fired generators[4]. In some cases, the values for PM-10 were around $0.01/MWh. Some more recent cursory analysis by the CBEE, which used lower externality values, reached similar results.

Thus, we suggest that the pollutant species that are most likely to contribute significantly to externality values in California are NOx and CO_2. NOx is regulated at the Federal and state levels, and it is traded in national and local (e.g., South Coast AQMD) emission-credit trading markets. CO_2, on the other hand is not presently regulated, and is traded only in thin, immature markets. Nevertheless, these two pollutants appear to be the most important regarding the environmental value of energy-efficiency programs in California.

Although it is unlikely that other pollutant species will be important in quantitative terms, the TDV team should monitor any major changes in the regulatory or market action regarding PM-10 (and increasingly PM-2.5) as well as SO_2 (particularly with regard to out-of-state sources). E3 does not expect VOCs, CO or other species to be significant contributors to environmental externality values during the foreseeable future.

---

[2] Fuel oil is noted as it also emits sulfur byproducts when burned, though much less than coal.

[3] Pace Univ. Center for Environmental Legal Studies, *Environmental Costs of Electricity*, Oceana Press, New York, 1990; Electric Power Research Institute (EPRI), *Environmental Externalities: An Overview of Theory and Practice*, EPRI CU/EN-7294, EPRI, Palo Alto, CA, 1991; National Renewable Energy Laboratory (NREL), *Issues and Methods in Incorporating Environmental Externalities into the Integrated Resource Planning Process,* NREL TP-461-6684, NREL, Golden, CO, 1994; U.S. Dept. of Energy, *Electricity Generation and Environmental Externalities: Case Studies*, DOE/EIA-0598, DOE Energy Information Agency, Washington, 1995.

[4] Note that SO_2 would be more important with emission factors typical of coal-fired generators.

CALIFORNIA
ENERGY
COMMISSION

MARKET CLEARING PRICES UNDER ALTERNATIVE RESOURCE SCENARIOS

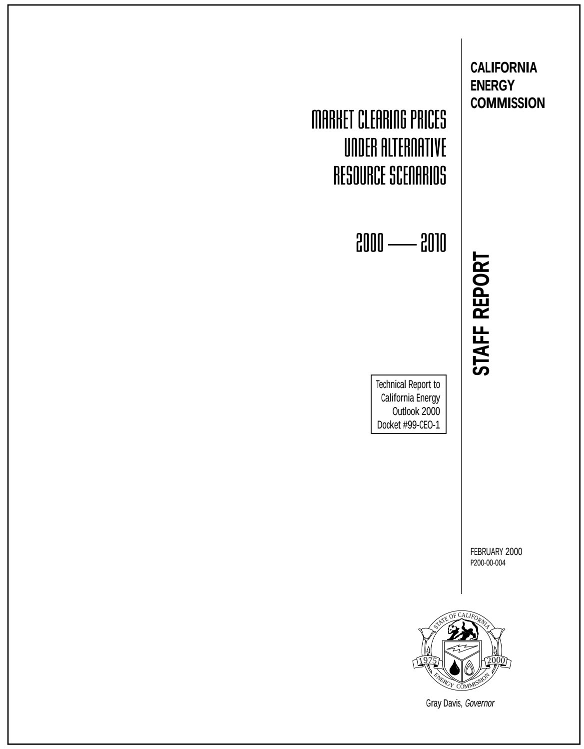
2000 — 2010

Technical Report to
California Energy
Outlook 2000
Docket #99-CEO-1

STAFF REPORT

FEBRUARY 2000
P200-00-004

Gray Davis, *Governor*



CALIFORNIA
ENERGY
COMMISSION

MARKET CLEARING PRICES
UNDER ALTERNATIVE
RESOURCE SCENARIOS

2000 —— 2010

STAFF REPORT

Technical Report to
California Energy
Outlook 2000
Docket #99-CEO-1

FEBRUARY 2000
P200-00-004

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

Richard Grix,
Principal Author

Karen Griffin,
Manager

ELECTRICITY
ANALYSIS
OFFICE

H. Daniel Nix,
Deputy Director

ENERGY
INFORMATION
& ANALYSIS
DIVISION

Steve Larson,
Executive Director

STAFF REPORT

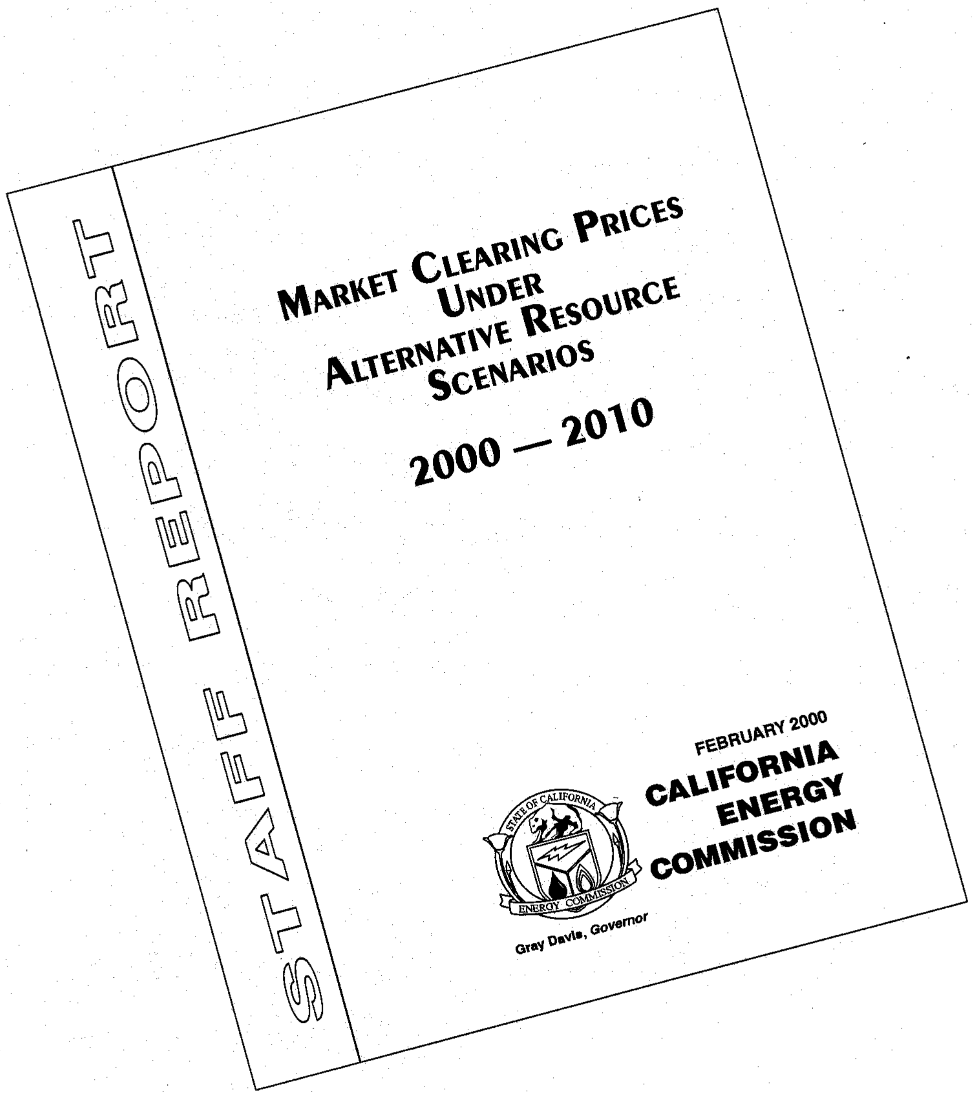
MARKET CLEARING PRICES UNDER ALTERNATIVE RESOURCE SCENARIOS

2000 — 2010

CALIFORNIA ENERGY COMMISSION

Gray Davis, *Governor*

P300-00-001


STAFF REPORT

MARKET CLEARING PRICES UNDER ALTERNATIVE RESOURCE SCENARIOS

2000 — 2010

FEBRUARY 2000

CALIFORNIA ENERGY COMMISSION

Gray Davis, Governor

CALIFORNIA ENERGY COMMISSION

Richard Grix, *Principal Author*
Karen Griffin, *Manager*

ELECTRICITY ANALYSIS OFFICE

H. Daniel Nix

ENERGY INFORMATION & ANALYSIS DIVISION

Table of Contents

Acknowledgments

Principal Authors and Multisym™ Modelers
Electricity Analysis Office
Angela Tanghetti
David Vidaver
Richard Grix

Contributors
Electricity Analysis Office
Denny Brown
Jerry Green
Joel Klein
Steve Layman
Ruben Tavares
Connie Leni
Bob Grow

Demand Analysis Office
Richard Rohrer

Fuel Resources Office
Bill Wood
Jairam Gopal

Electricity Analysis Office Manager: Karen Griffin
Demand Analysis Office Manager: Thom Kelly
Fuel Resources Office Manager: Gerry Bemis
Energy Information & Analysis Division Deputy Director: Daniel Nix

Executive Summary

In this report, the California Energy Commission staff evaluates the impact of two alternative resource development scenarios on market clearing prices for electricity purchased in California's wholesale market for the years 2000 through 2010. One resource scenario reflects rapid development of many currently announced projects and the other a more cautious rate of resource development driven by energy prices. Staff found that if eleven large power plants are put into service between 2001 and 2003, there would be more generation available than load growth requires over most of the ensuing decade. With this excess generation competing in the market, energy prices would decline below what is estimated as necessary to fund new generation. Developers are unlikely to build generation when the prospects for making a profit are so bleak. To proceed on the rapid development scenario, they would need to have alternative income sources, a significantly cheaper facility (or financing), or a perspective that some aspect of the future market is likely to be different from what is assumed in the staff's analysis.

The staff's forecasts of market clearing prices for these two scenarios for all years in the forecast period are based on the results from a regional market model. The approach attempts to capture the independent nature of resource development decisions. It is based on specific assumptions about the timing and quantity of new resource additions and provides useful insight as to how electricity prices in the competitive market would respond to an influx of new supply.

In developing the scenarios, the staff first evaluated over 40 proposed power plant projects for their likelihood of being built in California within the 2000 – 2010 time frame. This evaluation considered the potential for interzonal and intrazonal transmission congestion, natural gas availability, possible difficulty in mitigating environmental impact as well as the likelihood of local opposition. Based on these factors, the staff identified 19 plants, representing 9,186 MW, to include in the scenarios. Another 157 MW of capacity from new renewable energy projects were assumed to be built in the forecast period for a total of 9,343 MW of new capacity. For scale, this is approximately 14 percent of today's California capacity.

The rapid development scenario has 2,840 MW of capacity being added in 2002 and another 6,398 MW in 2003. The remaining additions involve one replacement/repowering of capacity in 2006 and another in 2008 for net additions of 104 MW. This rapid development leads to electricity wholesale prices dropping from a 2001 high of $30.3/MWh to a low of 21.9 $/MWh by 2003 (constant dollars). Market clearing prices are low until 2009 when they recover to current levels.

The cautious development scenario spreads out, in time, the development of the same projects included in the rapid development scenario. The same capacity is added in 2002, but only 1,819 MW are built in 2003. Eight projects that were added under the rapid development scenario in 2003 are deferred. This cautious development leads to prices dropping only to $23.7/MWh in 2003 and hovering about $2/MWh higher than the rapid development prices through the middle of the decade.

As a general guideline for adding new capacity, the staff used a reserve margin of 7 percent as an indicator of when to add plants that would be cost-effective to their owners. Planning reserve margins historically have been in the 15-20 percent range. The planning margin was intended to ensure that sufficient generation capacity existed at the time of the peak demand to cover supply and demand contingencies, and still meet minimum operating reserve requirements. If new load growth caused planning margins to drop to the 7 percent level, staff believed that prices would rise sufficiently to attract new entry. Our market simulations showed that this assumption may not be valid.

Overall, the staff believes that reserves will be lower in a competitive market as compared to a regulated market because of economic pressure to use resources more efficiently. Factors contributing to this include the following:

- A greater reliance on load diversity among regions in the West and an increase in regional transfers of electricity,

- Improved plant availability during peak demand hours which in large part determine whether a generator will make a profit for the year, and

- Greater demand-side responsiveness to high prices during the peak.

Because the staff is using a regional market model that simulates the loads and resources of the entire region encompassed by the Western Systems Coordinating Council (WSCC), it was also necessary to make certain assumptions about new additions outside of California. Of the 26,309 MW of new generation proposed for the WSCC outside of California, 7,173 MW were judged to have a high probability of being built because they were already under construction or had received all necessary regulatory approval. This amount of new capacity, however, was not enough to maintain the reliability of certain subregions of the WSCC outside of California. Staff added capacity to a subregion outside of California if its planning reserves fell below 6 percent. The staff, however, let reserves in some subregions drop below 6 percent in recognition that these areas have historically met peak demand by relying heavily on purchases from other regions.

The resulting average annual MCPs from the staff's two scenarios were compared to the annual average revenue requirement of a new market entrant. This comparison provides a useful measure when, how much, and how consistently, new entry is likely to be attracted to the California market in the next decade. Based on a fixed cost revenue requirement of $97/kW-year for a combined cycle plant and $72/kW-year for a combustion turbine and variable costs of $19/MWh and $26/MWh respectively, the market simulations indicate that market prices are insufficient to fund new generation between 2003 and 2009 for both scenarios.

In developing the annual average revenue requirement for a new market entrant, the staff found that the cost of capital for financing these projects and the cost of fuel are the two variables that will weigh heavily in determining the plant's competitiveness and ultimately its profitability. The cost of capital for a new market entrant is especially sensitive to lenders' and investors' perceptions of market uncertainty and risk. Some of that risk is attributable to the immaturity of the competitive market itself and should diminish over time.

Other factors that contribute to market uncertainty and risk include: the frequency and magnitude of price spikes; the development of the demand-side of the market and its effectiveness in moderating price volatility; the presence of price caps in both the energy and ancillary services markets; the development of the rules governing congestion costs; and the mechanisms/process for deciding when upgrades to the transmission system will occur.

Regulatory actions such as changes in environmental laws, both at the regional and national level, and the pace of restructuring in other western states and the rules adopted by these states for treatment of stranded asset costs and mitigating market power, will also shape investors' perceptions of market risk and uncertainty.

Both scenarios show that market clearing prices would not be sufficient to cover the annual average revenue requirement of a new market entrant until 2010. This finding underscores three trends that the staff believes will have a significant impact on future system reliability.

- Future generation resource additions will not occur in a smooth even pattern, but will more likely occur in a cyclical pattern resulting in periods of excess and lean generation capacity.

- A new generator's profitability will depend largely on the prices it is paid for energy during the summer peak demand season, if it is relying solely on the energy market for revenue.

- Market clearing prices during the summer peak demand season may not reach a level necessary to sustain new market entry until reserve margins drop below historic levels usually regarded as necessary for reliable service.

Developers of new power plants will be closely watching how market prices respond to new entry in 2002. Should prices behave in a manner consistent with staff's modeling, subsequent additions of new capacity will most likely be fewer and more spread out than the level assumed in staff's cautious development scenario. Staff will be conducting additional analyses to estimate the impacts of other key variables on market price and supply adequacy trends.

Introduction

In this report, the California Energy Commission staff provides two forecasts of the market clearing price (MCP) for electricity purchased through a second price auction such as that used by the California Power Exchange's (PX) day-ahead energy market. The two MCP forecasts are based on different resource development futures: one reflecting rapid development of many currently announced projects; the other, a more gradual rate of resource development driven by market prices.

The energy market is the principal source of income for most generators in California. Forecasts of future MCPs are therefore an indicator of future profitability for generators. MCPs also provide an important price signal to potential new generators. Developers of new power plants will compare the plant's revenue requirements to the expected revenue from the energy market. Broadly speaking, electricity prices higher than the level needed to cover the plant's revenue requirement indicate new generation capacity is needed; lower prices indicate a surplus of generation capacity exists. In reality, the market structure is more complicated, especially since loads at California's summer peak are so much higher than loads the rest of the year. Both the demand and supply sides of the market will need to adjust to better balance the value of their electricity investments.

Section I of the report begins with a comparison of the two forecasts of annual average MCPs for the years 2000-2010 and discusses the changes in both methodology and inputs underlying this forecast compared to the staff's December 1998 Market Clearing Price forecast.

Section II discusses how the staff developed the scenarios and the decision process involved in determining how much and when new resources would be added both in California and the rest of the Western Systems Coordinating Council (WSCC).

Section III looks at sources of market uncertainty, new market entry, and the emerging trends in future electricity prices that will have significant consequences for future system reliability.

Section I: Market Clearing Price Forecasts

This section provides two forecasts of MCPs[i] for electricity purchased through the PX. The PX oversees a competitive auction that determines the price of electricity on an hourly basis, according to the demand and supply bids submitted by buyers and sellers of electricity. The last generation bid accepted for meeting demand in a particular hour sets the MCP that the PX pays to all generators providing electricity in that hour.[ii] (See Appendix D for a more detailed explanation of the California market design.)

Each of the forecasts presented here represents a different point of view with respect to the timing of new generation additions. One forecast reflects a rapid development scenario in which merchant plant developers who have either received a permit to construct from the Energy Commission, filed an Application for Certification (AFC) with the Commission, or are expected to file an AFC within the next year, proceed immediately to construction as soon as they receive a license. The second forecast reflects the perspective that while new merchant plant developers may have a permit in hand from the Commission, they will adopt a wait-and-see strategy before commencing construction.

Construction of new generation facilities could stretch out because, unlike the regulated market where the recovery of construction costs was guaranteed, the competitive market provides no such guarantees. The staff’s second scenario is, therefore, based on the assumption that new power plants will be built when developers perceive that the market price for electricity will be high enough to allow them to recover their costs and make a profit.

The staff’s forecast of average monthly MCPs is best characterized as the expected trend. Actual average monthly MCPs will fluctuate above or below the forecasted MCPs because actual weather/demand, fuel prices, and outage conditions will vary from those assumed in staff’s forecast.

Table I-1 below compares the annual average MCPs from the two scenarios in nominal dollars and real year 2000 dollars. Both scenarios show MCPs declining in nominal and real dollars from 2001 to 2003 due to new power plants coming on-line. The decline under the rapid development scenario is greater because more power plants are added to the system in 2002 and 2003 than are added under the cautious development scenario. From 2003 to 2010, prices rise as demand grows and fewer power plants are built. In 2009, real prices return to their year 2000 levels. The two scenarios are described in greater detail in **Section II** of the report. **Figures I-1** and **I-2** illustrate the difference between the nominal and real annual average MCPs for the two scenarios.

Table I-1
Comparison of Annual Average MCPs
Under Two Development Scenarios
($/MWh)

Year	Rapid Development		Cautious Development	
	Nominal	2000$	Nominal	2000$
2000	28.5	28.5	28.5	28.5
2001	31.0	30.3	31.0	30.3
2002	25.9	24.7	25.9	24.8
2003	23.4	21.9	25.3	23.7
2004	24.8	22.7	26.9	24.6
2005	26.3	23.6	29.1	26.1
2006	27.7	24.2	30.7	26.9
2007	29.1	24.9	31.0	26.5
2008	29.9	24.9	33.2	27.6
2009	36.0	29.1	36.0	29.1
2010	41.9	32.9	41.9	32.9
Annual Growth Rates				
2000-2003	-6.3%	-8.3%	-3.9%	-6.0%
2003-2010	8.6%	6.0%	7.5%	4.8%

Figure I-1
Comparison of Nominal vs. Real
Annual Average MCPs

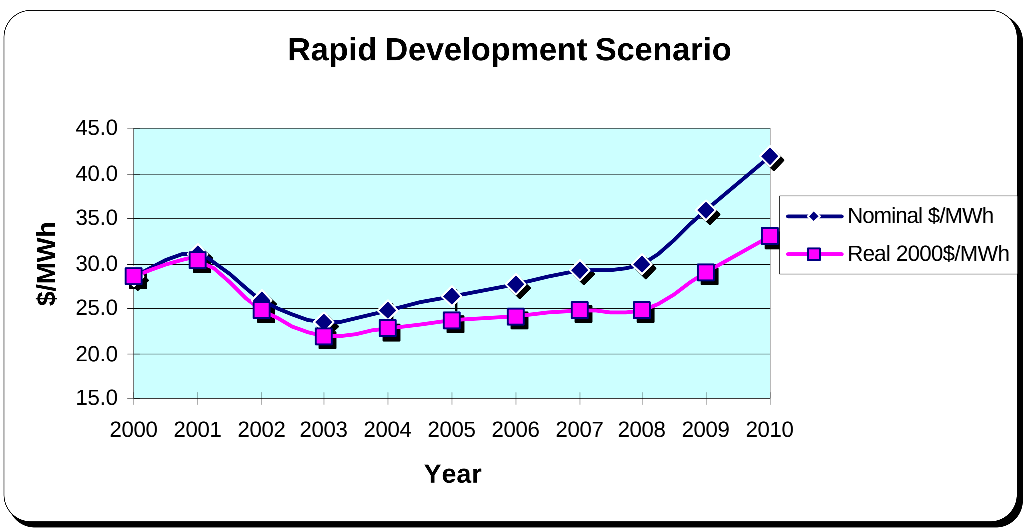
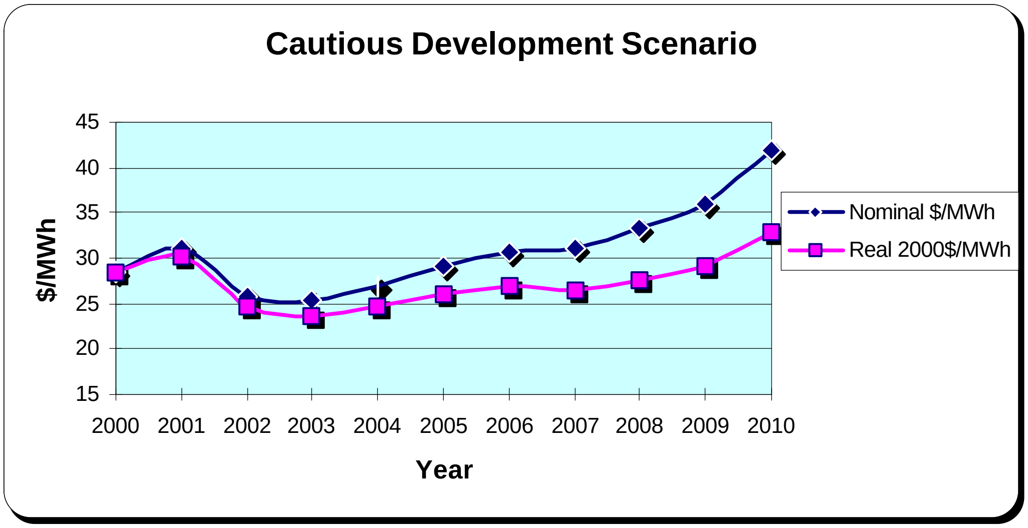


Figure I-2
Comparison of Nominal vs. Real
Annual Average MCPs



Tables I-2 and **I-3** below compare the results of these two alternative resource scenarios to the staff's December 1998 Market Clearing Price forecast.

Table I-2
Rapid Development Scenario
Annual MCPs (Nominal $/MWh)

Year	2000 Forecast	1998 Forecast	% Diff
2000	28.5	26.5	8%
2001	31.0	27.8	3%
2002	25.9	29.6	-13%
2003	23.4	30.6	-23%
2004	24.8	31.9	-22%
2005	26.3	33.1	-20%
2006	27.7	34.5	-20%
2007	29.1	36.0	-19%
2008	29.9	37.5	-20%
2009*	36.0	38.6	-7%
2010*	41.9	39.9	5%

* Staff's 1998 Forecast was for the years 1999-2008.
The 2009 and 2010 values are extrapolated

Table I-3
Cautious Development Scenario
Annual MCPs
(Nominal $/MWh)

Year	2000 Forecast	1998 Forecast	% Diff
2000	28.5	26.5	8%
2001	31.0	27.8	3%
2002	25.9	29.6	-13%
2003	25.3	30.6	-17%
2004	26.9	31.9	-16%
2005	29.1	33.1	-12%
2006	30.7	34.5	-11%
2007	31.0	36.0	-14%
2008	33.2	37.5	-11%
2009*	36.0	38.6	-7%
2010*	41.9	39.9	5%

* Staff's 1998 Forecast was for the years 1999-2008.
The 2009 and 2010 values are extrapolated.

The MCP results for both scenarios are identical in the years 2000 through 2002 and 2009 through 2010. The results are identical because, in the market model[iii] used to produce these estimates of MCPs, the amount of existing and new generation capacity available in these years is identical. The differences between the MCPs from the 1998 forecast and the two scenarios presented in this report are largely attributable to a different methodology, for the years after 2001, and to a different gas price forecast.

Changing Methodology

Both this forecast and the staff's 1998 MCP forecast relied on the results of a regional market model. However, in the previous MCP forecast, the staff only used the MCP results from the model until the annual MCP reached the annual revenue requirement of a new market entrant. Annual MCPs from the model reached this level in the year 2002. Once market prices reached that level, the annual MCP was set equal to the annual revenue requirement of the new entrant. It was the staff's judgement that if the actual MCP fell short of the annual revenue requirement of the new entrant then the viability of the market would be questionable and the Independent System Operator (or the legislature) would have to take remedial action. Market interventions could include capacity payments or other forms of remuneration such as must-run contracts, to attract entry. We were uncertain whether market forces would be allowed to operate if reserve margins dropped below historic levels. Conversely, if the MCP exceeded the revenue requirement of a new market entrant this would attract new entry and drive the MCP lower. **Table I-4** illustrates how the 1998 MCP forecast was constructed. From 1998 to 2001 the 1998 MCP forecast is derived from the market model results. After 2002, the 1998 MCP forecast is equal to the cost of a new entrant.

Table I-4
Construction of 1998 MCP Forecast
(Nominal $/MWh)

Year	Market Model Results	Cost of a New Entrant	MCP Forecast
1998	25.8	28.5	25.8
1999	24.7	27.5	24.7
2000	26.5	27.8	26.5
2001	27.8	28.6	27.8
2002	31.6	29.6	29.6
2003	36.6	30.6	30.6
2004		31.9	31.9
2005		33.1	33.1
2006		34.5	34.5
2007		36.0	36.0
2008		37.5	37.5

Natural Gas Prices

MCPs are very sensitive to the price of natural gas because gas-fired power plants are the plants that set the MCP during most of the peak demand hours. This MCP forecast for the years 2000 and 2001 is 8 percent and 3 percent higher than the MCPs in staff's 1998 forecast largely because of differences between the natural gas prices underlying the two forecasts. **Table I-5** below compares the statewide average gas price from the ***Preliminary 1999 Fuels Report*** (***FR99***) to the previous ***1997 Fuels Report*** (***FR97***) gas price forecast.

Natural gas prices for this current forecast are significantly higher than those used in the 1998 MCP forecast, due primarily to increases in the commodity cost of gas. The methodology underlying the ***FR97*** forecast assumed that the investor-owned utilities (IOUs) retained ownership of their fossil fuel-fired power plants. The IOU's divestiture of these plants affected certain assumptions within the new ***FR99*** forecast. First, the utilities' revenue allocation formula changed to recover more revenue from the electric generation customers. Second, in the ***Preliminary FR99*** forecast, the staff assumed that the gas supply pool from which divested plants purchase their gas will be more expensive than the sources the California IOUs had access to when they owned the plants. Once the utilities sold their fossil-fuel plants, the associated contracts for firm interstate gas pipeline capacity were assumed to be no longer applicable. Additional detail on the ***FR99*** gas prices and the price forecast methodology is available in **Appendix A**.

Table I-5
Comparison of Statewide Average Natural Gas Price Forecasts
Cost of Gas to Electric Generators (EG)*
2000$

Year	Preliminary FR99 EG $/MMBtu	Final FR97 EG $/MMBtu	% Diff
2000	2.54	2.22	14%
2001	2.52	2.26	11%
2002	2.48	2.30	8%
2003	2.53	2.35	8%
2004	2.58	2.39	8%
2005	2.62	2.44	7%
2006	2.65	2.47	7%
2007	2.69	2.51	7%
2008	2.72	2.56	6%
2009	2.76	2.60	6%
2010	2.79	2.62	7%

*Average created by weighting the gas price forecasts for PG&E, SoCal Gas, and SDG&E by 0.6, 0.3, and 0.1 respectively.

Developing Bids

The hourly bids submitted by generators to the PX determine the MCP. Modeling the function of a market such as the California PX, therefore, required that the staff develop these bids. Staff's regional simulation model Multisym™ allows the user two choices: to bid the plant's output at its variable operating cost, or to bid a portion or multiples of the plant's fixed and variable operating costs. For thermal plants, the variable operating cost is simply the product of a plant's incremental heat rate, measured in Btus/kWh, times its fuel cost ($/MMBtu), plus its variable operation and maintenance (O&M) cost. For hydro facilities the variable operating cost is simply its variable O&M.

In constructing the bids, the staff first identified those plants that would be price-takers, i.e., would not set the MCP, and those that had the potential to be price-setters, i.e., plants that could set the MCP. Large coal and nuclear plants, generators with Standard Offer contracts, and hydro facilities are treated as generation that is scheduled rather than bid and therefore are price-takers. They were bid in at their variable operating cost.

Potential price-setters were assumed to be in-state and out-of-state oil/gas-fired steam generators, combined-cycle plants and in-state combustion turbines. For these plants, a single bidding strategy was developed. Historical monthly PX prices were used as a guideline for estimating how much of the generators' fixed costs to include in their bids. Price-setting plants were first bid in at their variable operating cost. The resulting average monthly MCPs from the model were then compared to actual average monthly MCPs from the PX to date.

For most months of the year, the actual average monthly MCPs have been either at a level equal to, or lower than, the MCPs from the model when all plants were bidding in at the variable operating cost. The staff used information on factors that influence market conditions, such as temperature and resource availability, to determine whether the historical prices for a particular month were unusual, or what could be expected under average/ expected market conditions. Based on this information, the staff determined that for the months November through June all price-setting plants would bid their incremental operating cost.

For the period July through October, the staff made several runs where portions of the price-setting plant's variable O&M and fixed costs were added to their bids. These additions to bids were done until the resulting monthly average MCP from the model reached a level which the staff believed to be probable, given the underlying assumptions in the model with respect to resource availability and demand and the historical performance of the market. **Table I-6** provides the historical monthly unconstrained MCP for 1998 and 1999 along with the monthly forecast of MCPs from the Multisym™ model for the years 2000 and 2001. **Figure I-3** illustrates that the forecasted monthly values closely follow the historical trend in PX prices.

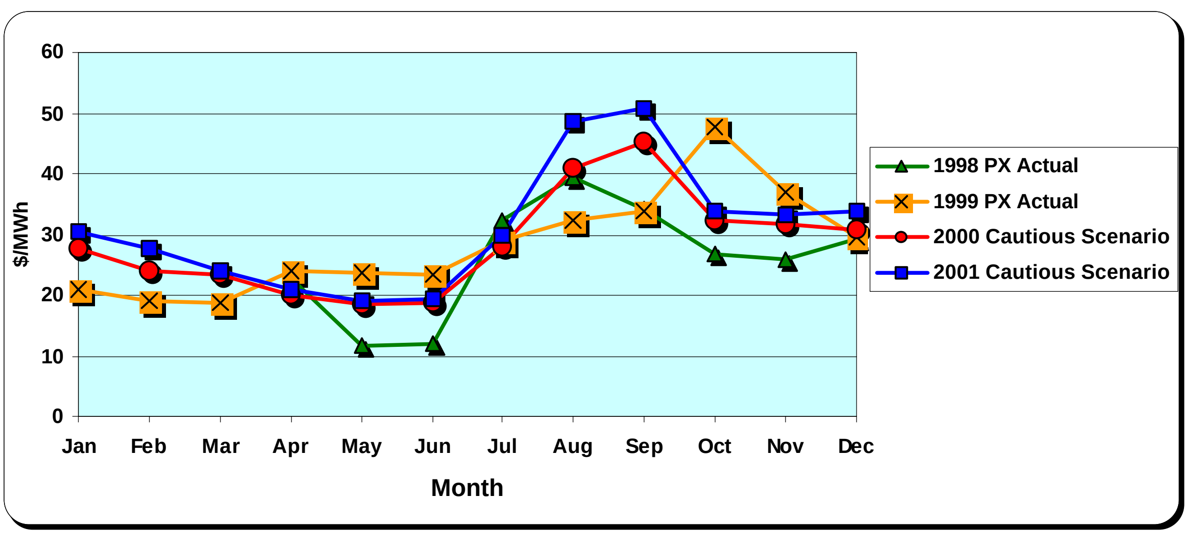
To the extent that the forecasted monthly prices deviate significantly from historical monthly prices, such as those that occurred in October 1999, these differences can be attributed to abnormal market conditions influencing the price. (**Appendix B**, which compares last year's forecast to the historical PX market, describes those unique market conditions that caused market prices to deviate from what would have occurred under expected/average market conditions.)

Although the PX market has only two years experience, the expected trend in average monthly MCPs is low in the winter and spring, higher in the fall, and highest in the summer. The MCPs in 1998 followed this seasonal pattern, as does the staff's forecast of monthly MCPs. MCPs in 1999 exhibited a much different pattern. The monthly average MCP for the summer months was lower than the price for the fall and winter months. Factors contributing to these lower summer prices were an unusually mild summer and greater than expected hydro availability during the summer from the Northwest due to a late snow melt. The late snow melt also contributed to spring prices being higher than would be expected, since greater than normal levels of fossil generation were needed to replace the late hydro run-off. The high monthly average MCPs seen in October and November were the result of a combination of factors including warmer than expected temperatures, derates on the transmission lines between California and the Northwest and on the transmission lines connecting northern and southern California, and unexpected plant outages.

Table I-6
Comparison of Historical Monthly MCPs
To Forecasted MCPs
($/MWh)

Month	1998 PX Actual	1999 PX Actual	2000 Forecasted	2001 Forecasted
Jan		21.0	27.7	30.4
Feb		19.0	24.1	27.7
Mar		18.8	23.3	24.1
Apr	22.6	24.0	20.0	20.8
May	11.6	23.6	18.5	19.2
Jun	12.1	23.5	18.8	19.4
Jul	32.4	28.9	28.0	29.8
Aug	39.5	32.3	40.9	48.6
Sep	34.0	33.9	45.3	50.9
Oct	26.6	47.6	32.2	33.9
Nov	25.7	37.0	31.6	33.1
Dec	29.1	29.7	30.7	33.9
----------	-------	-------	-------	-------
Average	26.0	28.3	28.5	31.0

Figure I-3
Comparison of Historical Monthly MCPs
To Forecasted MCPs
Under the Cautious Development Scenario



Monthly and Sub-Period MCPs

For both scenarios, in 2000 through 2002 and 2009 through 2010, the monthly MCPs are identical because the generation capacity in the model is identical. **Table I-7** and **Table I-8** provide the monthly MCPs from the Multisym™ model for the two scenarios for the years 2002 through 2010. (Monthly values for 2000 and 2001 were provided in **Table I-6**.)

Table I-7
Rapid Development Scenario
Monthly MCPs
(Nominal $/MWh)

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	26.6	23.0	24.3	25.8	26.9	27.1	30.1	33.4	38.1
Feb	24.8	22.4	22.6	24.8	25.9	26.2	26.8	32.0	34.5
Mar	22.0	20.8	21.7	23.0	23.8	24.1	25.7	28.2	29.7
Apr	20.1	19.3	20.3	21.4	22.5	22.7	24.0	25.0	26.7
May	18.6	17.4	18.7	20.1	21.1	22.3	23.3	24.7	26.4
Jun	18.8	17.5	18.9	19.9	20.6	22.0	23.2	24.9	26.6
Jul	26.7	26.0	27.6	29.1	30.7	32.5	26.5	37.0	42.7
Aug	32.1	28.2	30.2	32.6	34.7	38.6	45.9	57.5	75.3
Sep	34.7	29.3	31.3	33.3	34.9	38.8	40.3	58.7	75.3
Oct	29.6	27.9	29.6	30.7	31.9	34.2	27.6	39.4	43.6
Nov	27.9	24.3	25.4	27.0	28.7	29.7	31.6	34.8	41.6
Dec	28.4	24.8	26.5	28.0	29.8	30.9	33.5	35.6	41.3
Annual Avg.	**25.9**	**23.4**	**24.8**	**26.3**	**27.7**	**29.1**	**29.9**	**36.0**	**41.9**

Table I-8
Cautious Development Scenario
Monthly MCPs
(Nominal $/MWh)

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	26.6	25.0	26.6	28.9	28.1	28.1	31.1	33.4	38.1
Feb	24.8	23.6	23.6	26.8	26.7	28.0	27.4	32.0	34.5
Mar	22.0	21.4	22.9	24.1	24.4	24.8	26.5	28.2	29.7
Apr	20.1	20.5	21.9	22.9	23.2	23.6	24.3	25.0	26.7
May	18.6	19.0	20.0	21.2	22.5	23.0	23.7	24.7	26.4
Jun	18.8	19.2	20.2	21.1	22.5	22.8	23.8	24.9	26.6
Jul	26.7	27.1	28.8	30.5	32.6	33.9	34.9	37.0	42.7
Aug	32.1	31.0	33.7	38.6	45.7	44.3	50.2	57.5	75.3
Sep	34.7	32.2	35.9	40.3	47.1	44.1	51.1	58.7	75.3
Oct	29.6	29.0	31.1	32.0	34.0	35.3	37.0	39.4	43.6
Nov	27.9	27.0	28.9	30.7	30.6	31.1	33.0	34.8	41.6
Dec	28.4	27.9	29.3	31.1	30.8	32.3	34.4	35.6	41.3
Annual Avg.	**25.9**	**25.3**	**26.9**	**29.1**	**30.7**	**31.0**	**33.2**	**36.0**	**41.9**

Tables I-9 and **I-10** present the same monthly information in real (2000) dollars.

Table I-9
Rapid Development Scenario
Monthly MCPs
($/MWh)
Real 2000$

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	25.4	21.5	22.3	23.1	23.5	23.2	25.1	27.1	29.9
Feb	23.7	20.9	20.7	22.2	22.7	22.3	22.3	25.9	27.1
Mar	21.0	19.5	19.9	20.6	20.8	20.6	21.4	22.8	23.3
Apr	19.2	18.1	18.6	19.2	19.7	19.4	19.9	20.2	21.0
May	17.8	16.3	17.1	18.0	18.5	19.0	19.4	20.0	20.7
Jun	18.0	16.4	17.3	17.8	18.1	18.7	19.3	20.2	20.9
Jul	25.5	24.3	25.3	26.1	26.9	27.8	22.0	30.0	33.6
Aug	30.7	26.4	27.7	29.2	30.4	33.0	38.2	46.5	59.2
Sep	33.2	27.4	28.7	29.8	30.5	33.1	33.6	47.5	59.2
Oct	28.3	26.1	27.1	27.5	27.9	29.2	23.0	31.9	34.3
Nov	26.7	22.7	23.3	24.2	25.1	25.4	26.3	28.2	32.7
Dec	27.2	23.2	24.3	25.1	26.1	26.3	27.9	28.8	32.5
Annual Ave.	**24.7**	**21.9**	**22.7**	**23.6**	**24.2**	**24.9**	**24.9**	**29.1**	**32.9**

Table I-10
Cautious Development Scenario
Monthly MCPs
($/MWh)
Real 2000$

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	25.4	23.4	24.3	25.9	24.6	24.0	25.8	27.1	29.9
Feb	23.7	22.1	21.6	24.0	23.4	23.9	22.8	25.9	27.1
Mar	21.0	20.0	21.0	21.6	21.3	21.2	22.0	22.8	23.3
Apr	19.2	19.2	20.1	20.5	20.3	20.1	20.2	20.2	21.0
May	17.8	17.8	18.4	19.0	19.7	19.6	19.7	20.0	20.7
Jun	18.0	17.9	18.5	18.9	19.7	19.5	19.8	20.2	20.9
Jul	25.5	25.3	26.4	27.3	28.5	28.9	29.0	30.0	33.6
Aug	30.7	29.0	30.8	34.6	40.0	37.8	41.8	46.5	59.2
Sep	33.2	30.1	32.9	36.1	41.3	37.7	42.5	47.5	59.2
Oct	28.3	27.2	28.4	28.7	29.8	30.1	30.8	31.9	34.3
Nov	26.7	25.2	26.5	27.6	26.7	26.5	27.5	28.2	32.7
Dec	27.2	26.1	26.8	27.9	27.0	27.6	28.6	28.8	32.5
Annual Ave.	**24.7**	**23.7**	**24.6**	**26.1**	**26.9**	**26.5**	**27.6**	**29.1**	**32.9**

The staff developed subperiod MCPs for an average weekday and weekend by peak and off-peak periods by creating hourly MCPs for each month using a scaling routine based on a simple regression analysis that correlated historical hourly MCPs and hourly PX load for each month. Each month is represented as an equivalent week (168 hours). The scaling routine was first developed for our 1998 MCP forecast and has been modified slightly for this forecast.[iv] The hourly and subperiod MCPs for both scenarios for all months in the forecast years are available in EXCEL spreadsheets that can be downloaded from the Commission web site.

Table I-11 provides the average annual, on-peak and off-peak subperiod MCPs for an average weekday from the rapid development scenario. Peak hours are defined as Monday through Sunday 7:00 a.m. to 11:00 p.m.. The off-peak period is the remaining hours, Monday through Sunday 11:00 p.m. to 7:00 a.m.. The annual average MCP for the off-peak period is between 42 and 43 percent lower than the peak period MCP. **Figure I-4** illustrates the difference between weekday on-peak and off-peak period MCPs. **Table I-12** and **Figure I-5** provide the same information for an average weekend day. **Tables I-13** and **I-14** and **Figures I-6** and **I-7** provide the subperiod weekday/weekend day data for the cautious development scenario.

The staff notes that all the MCPs presented here are an average for the entire ISO control area. We have not provided separate MCPs for the three ISO congestion management zones (northern, central, and southern California). Zonal price differences do exist and at times can be significant. These price differences should decrease over time. If prices are higher in one zone because of congestion, these high prices will provide a price signal to new generators to locate in that zone, thus eliminating the congestion and lowering the zone's MCP. In specific situations, a price might not rise sufficiently to justify a plant, because power plants are "lumpy investments" and are not available in an infinite number of sizes matched exactly to local needs. And, even if prices do justify a plant, local conditions may be so constrained by other parameters that a plant is not built.

Table I-11
Subperiod MCPs
Average Weekday
Rapid Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	30.4	35.4	20.5
2001	33.2	38.6	22.3
2002	27.6	32.1	18.6
2003	25.0	29.1	16.8
2004	26.5	30.8	17.8
2005	28.1	32.8	18.9
2006	29.6	34.4	19.8
2007	31.1	36.3	20.8
2008	32.0	37.3	21.4
2009	38.5	44.9	25.7
2010	44.9	52.4	29.8

Figure I-4
On-Peak vs. Off-Peak Period MCPs
Average Weekday
Rapid Development Scenario
($/MWh)

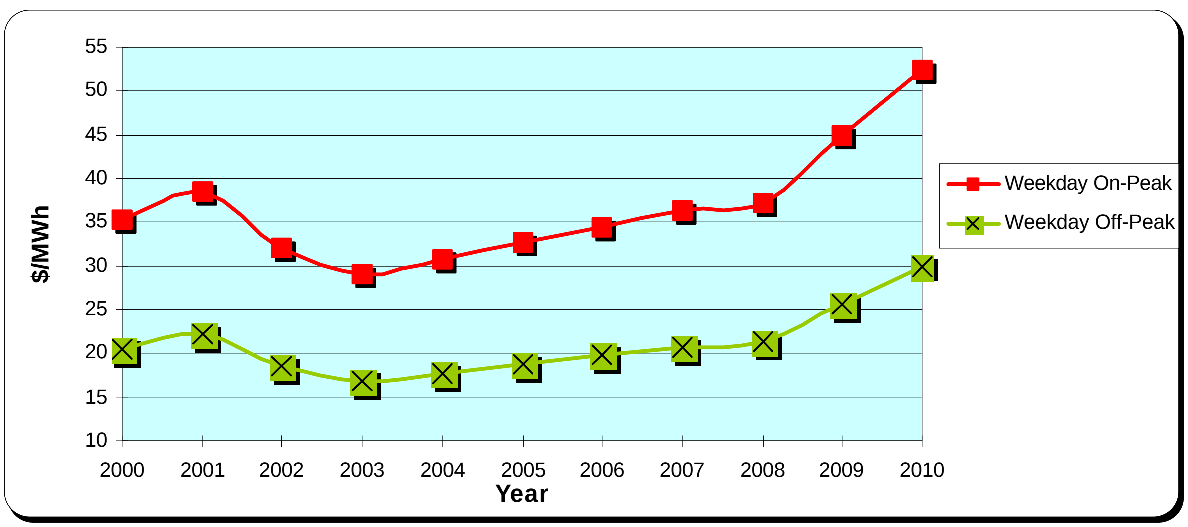


Table I-12
Subperiod MCPs
Average Weekend Day
Rapid Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	23.5	26.3	18.0
2001	25.6	28.6	19.6
2002	21.5	24.0	16.4
2003	19.4	21.8	14.8
2004	20.5	23.0	15.6
2005	21.8	24.4	16.5
2006	22.9	25.7	17.4
2007	24.1	27.0	18.3
2008	24.7	27.7	18.8
2009	29.6	33.1	22.6
2010	34.3	38.4	26.3

Figure I-5
On-Peak vs. Off Peak Period MCPs
Average Weekend Day
Rapid Development Scenario
($/MWh)

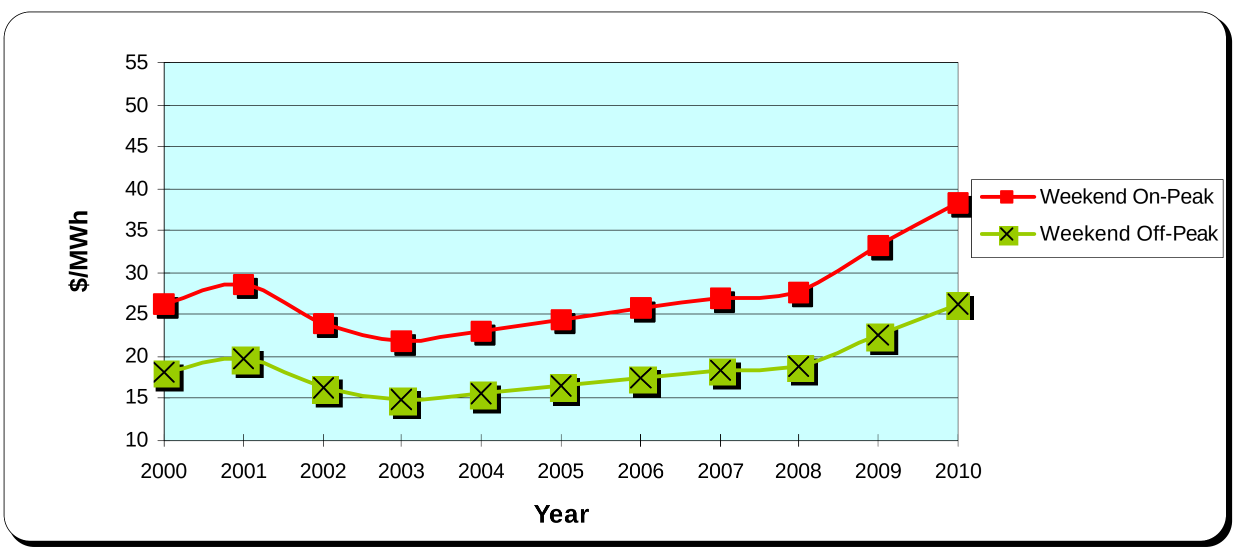


Table I-13
Subperiod MCPs
Average Weekday
Cautious Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	30.4	35.4	20.5
2001	33.2	38.6	22.3
2002	27.6	32.1	18.6
2003	27.0	31.4	18.1
2004	28.8	33.5	19.3
2005	31.1	36.2	20.8
2006	32.9	38.4	21.9
2007	33.1	38.6	22.1
2008	35.5	41.4	23.7
2009	38.5	44.9	25.7
2010	44.9	52.4	29.8

Figure I-6
On- Peak vs. Off Peak Period MCPs
Average Weekday
Cautious Development Scenario
($/MWh)

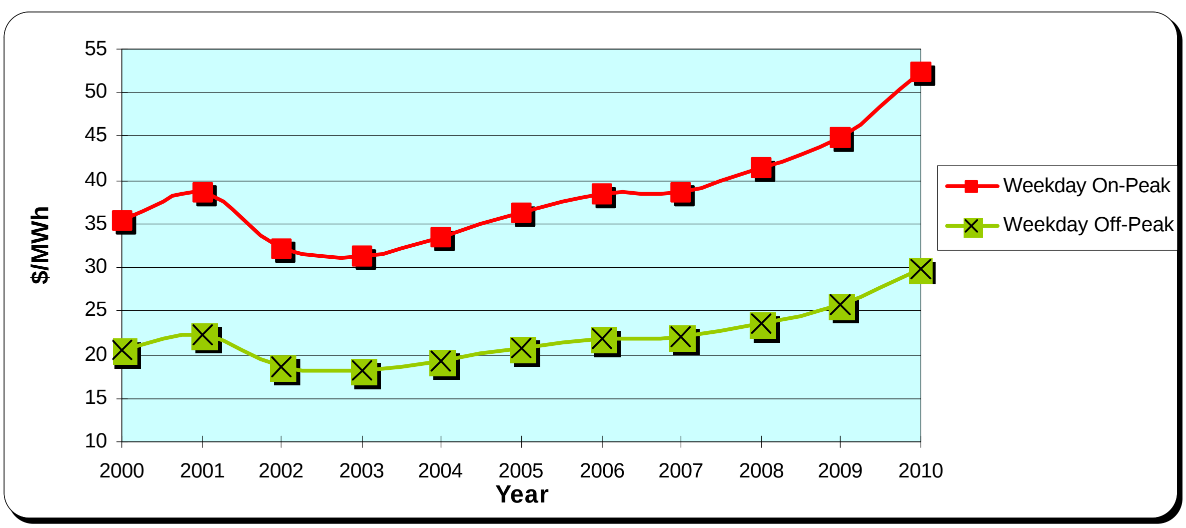
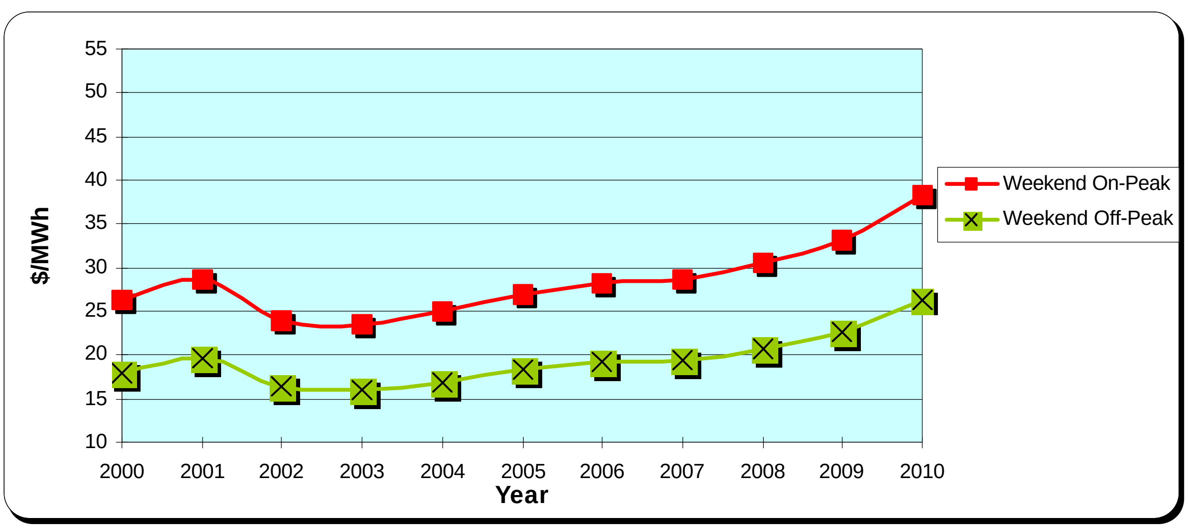


Table I-14
Subperiod MCPs
Average Weekend Day
Cautious Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	23.5	26.3	18.0
2001	25.6	28.6	19.6
2002	21.5	24.0	16.4
2003	20.9	23.5	15.9
2004	22.3	25.0	17.0
2005	24.0	26.9	18.3
2006	25.3	28.3	19.2
2007	25.5	28.6	19.4
2008	27.3	30.6	20.8
2009	29.6	33.1	22.6
2010	34.3	38.4	26.3

Figure I-7
On-Peak vs. Off-Peak Period MCPs
Average Weekend Day
Cautious Development Scenario
($/MWh)



[i] All MCPs referred to in this report are for the PX's hourly day ahead unconstrained market and unweighted by load.

[ii] Until March 2002, California's investor-owned utilities (PG&E, SCE, and SDG&E) must buy from *and* sell *all* of their generation through the California Power Exchange (PX), which will auction electric power demand and supply. Other market participants — such as independent power producers (IPPs), municipal generators, and utilities located outside of California, aggregators, etc. — have the option of buying from, or selling electricity through the PX or selling directly to a customer without going through the PX.

[iii] The MCPs from the staff's two scenarios were outputs of the Multisym™ model, a licensed product of Henwood Energy Services Inc. Multisym™ emulates the hourly bidding market of the California PX, as well as the commitment and dispatch of generators and the transmission of electricity throughout the WSCC reliability region.

[iv] See Appendix D, "Hourly MCP Scaling Methodology," in *1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues*, California Energy Commission, December 1998, Publication No. 300-98-015.

Section II: Alternative Development Scenarios

This section describes how the staff constructed their two scenarios of future power plants additions for California and the rest of the WSCC. When the staff prepared the 1998 MCP forecast, six Applications for Certification (AFCs) for new power plants had been filed with the Energy Commission. By the end of 1999, three of the six AFCs had been approved, and developers had proposed to build another 34 large gas-fired power plants in the State. These 34 projects include those where the developer has either filed an AFC, has made a public announcement regarding their intent to file an AFC, or has contacted the Commission staff privately but has not made any public announcement about filing an AFC.

Because of the large number of new power plants proposed in the State, the staff believes that using the assumption that the annual revenue requirement of a new market entrant would determine the long-run MCP would be inaccurate. The staff believed that a new approach, based on specific assumptions about the timing and quantity of new resource additions, would more accurately describe future MCPs in the competitive market. The capacity of proposed new plants significantly exceeds peak demands from load growth and would materially impact prices.

In-State Additions

It is highly speculative as to which power plants will be built and when. The staff viewed it as unlikely that all of the plants that developers have indicated an interest in building will be built within the MCP forecast period. This assumption, of course, is sensitive to whether certain existing resources, such as the nuclear plants and older fossil fuel-fired plants that are receiving reliability must-run payments, will continue to operate in the future. In deciding which proposed plants to include in the forecast, the staff first included those that had already received approval from the Commission or would likely receive approval within the next 6 months and still have an on-line date prior to the Summer of 2002.

After 2002, the staff relied on a combination of factors which would limit the number of plants and spread out the development of new projects amongst the major developers. Location was one of the factors considered because of doubts as to whether the existing transmission network could accommodate all these proposed plants without undergoing significant upgrades and increases in capacity.

Transmission congestion should provide an economic incentive as to where new generation should locate. For example, congestion on Path 15, which represented the border between the northern and southern California congestion pricing zones,[i] is congested primarily in the south to north direction. To relieve this congestion, generators in northern California receive a higher MCP, which should provide a stronger economic incentive for locating new generation in northern California. Therefore, the staff's additions of new resources tend to include more new generation in northern California over southern California.

Congestion within a zone (intrazonal congestion), as well as the adequacy of natural gas pipeline capacity, are two factors that the staff considered as potentially limiting the number of plants built within a zone. The staff's assessment of the potential for intrazonal congestion was based on an examination of the findings contained in the system impact studies submitted to the Commission as part of the certification process for new power plants.[ii] Two plants proposed for northern California were found to have their output limited to avoid transmission line overloads. Intrazonal congestion was not a problem in southern California because the transmission networks in southern California are highly interconnected and contain fewer radial transmission lines than northern California.

Natural gas pipeline capacity was found to be adequate in most of the state. Gas suppliers have also indicated that they are more than willing to increase gas pipeline capacity to an area if there is a demand. Increasing gas pipeline capacity is also a relatively easier task than building new transmission lines.

Proposed projects were also screened based on the Commission staff's estimate of which projects may have a more difficult time in mitigating potential environmental impacts, as well as the presence of local opposition. Projects that fell into this category were seen as having a lower probability of being built within the forecast period. Because of environmental concerns, projects that involved repowers or used existing power plant sites were viewed as having a higher probability of being built before "green" site projects.

Considering all of the factors described above, the staff judged that 19 of the proposed power plants had a higher probability of being built within the next ten years than the remaining 21. This number of plants represents a total of 9,186 MW of new net capacity being added. All of these plants are merchant plants assumed to be selling all of their output into the California PX. Another 157 MW of capacity from renewable energy projects was also added in the ISO control area over the next 10 years for a total of 9,343 MW.

The first development scenario, the rapid development scenario, relies on the information from developers regarding when they intend to build and operate their new power plants once the Commission approves their AFC. The details of this scenario are shown in **Table II-1**. The table shows new additions, retirements of existing capacity and replacement of that capacity with new or repowered capacity. Under the rapid development scenario, 2,840 MW are added in 2002 and another 6,398 MW in 2003. The remaining additions involve one replacement/repowering in San Diego in 2006 for a net 252 MW increase and another in central California in 2008 for a net 142 MW decrease. This results in 9,342 MW total.

Table II-2 provides the details of the cautious development scenario. This scenario assumes that proponents of multiple projects will take a more cautious approach, waiting to see how profitable their initial plants will be and if their competitor's plans materialize. Over the 2000 – 2010 forecast period, the same amount of capacity is added in this scenario as in the rapid development scenario. The difference between the two begins in 2003 when eight projects that were on-line in the rapid development scenario in 2003 are deferred in this scenario. The projects that are included in 2002 and 2003 are those that already have been approved by the Commission or are close to the end of the one-year licensing period and involve developments at existing sites. They were assumed to be approved. The eight plants that are deferred in this cautious development scenario come on-line later in the forecast period to prevent the planning reserve margin for the California ISO from falling below 7 percent.[iii]

Figure II-1 illustrates the differences between the two scenarios. In the rapid development scenario, ISO control area planning reserves reach a peak of 22 percent in 2003 and then steadily decline to 7 percent by 2010. In the cautious development scenario, planning reserves reach 13 percent in 2003. New resources are added in the years 2007, 2008, and 2009 to keep reserve margins above 7 percent. By 2010 reserves are at the 7 percent level.

Historically, a 15-20 percent planning reserve margin was regarded as the standard for maintaining adequate reliability. The planning margin was intended to ensure that sufficient generation capacity existed at the time of the peak demand to cover contingencies such as generation capacity and energy lost due to forced outages, dry hydro conditions, or demand forecast error, and still meet minimum operating reserve requirements.[iv] The WSCC[v] requires that control areas (areas that control generation and individually balance electrical load such as the California ISO) within its boundaries maintain a minimum operating reserve of 7 percent.

By using a 7 percent margin as an indicator of when to add new resources in the cautious development scenario, the staff assumed that MCPs would reflect the value of additional generation at the margin, and would be high enough to support investment. This would preserve minimum operating reserve levels.

Table II-3 provides the load-resource balance for the entire State under the cautious development scenario. Outside of the California ISO control area, very few power plants are added in the State over the next ten years. In the LADWP service area, only 10 MW of new renewable energy projects are added. LADWP has ample supplies to meet its obligation to serve and has embarked on an ambitious cost reduction program. In the Imperial Irrigation District, 59 MW of renewable energy projects are added in 2002 and 148 MW of new combustion turbine capacity in 2003. Reserves for the entire State under the cautious development scenario peak at 16 percent in 2003 and reach 9 percent by 2010.

Table II-1
Rapid Development Scenario
California ISO Control Area
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Total Load	48,380	49,122	50,020	50,861	51,687	51,551	52,212	53,154	54,145	55,127	56,104	
Existing Resources-No Additions	56,326	56,247	56,080	55,958	55,982	54,719	54,689	54,567	54,477	53,963	53,819	
Interruptible Load	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	
Addition/Retirements By Region For Rapid Development Scenario												
Northern California												
Additions	0	0	877	3,722	0	0	0	0	0	0	0	**4,599**
Retirements	0	0	0	-430	0	0	0	0	0	0	0	**(430)**
Central California												
Additions	0	0	1,239	1,360	0	0	0	0	528	0	0	**3,127**
Retirements	0	0	0	-326	0	0	0	0	-676	0	0	**(1,002)**
Southern California												
Additions	0	0	722	2,290	0	0	0	0	0	0	0	**3,012**
Retirements	0	0	0	-634	0	0	0	0	0	0	0	**(634)**
San Diego												
Additions	0	0	2	416	0	0	962	0	0	0	0	**1,380**
Retirements	0	0	0	0	0	0	-710	0	0	0	0	**(710)**
Net CAL-ISO Capacity Additions	0	0	2,840	6,398	0	0	252	0	(148)	0	0	**9,342**
Existing Resources Plus Net Additions	56,326	56,247	58,920	65,196	65,220	63,957	64,179	64,057	63,819	63,305	63,161	
*** Margins Over Load With Net Additions**	**10%**	**8%**	**12%**	**22%**	**20%**	**18%**	**17%**	**15%**	**12%**	**9%**	**7%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e. interruptible) load.

Table II-2
Cautious Development Scenario
California ISO
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Total Load	48,380	49,122	50,020	50,861	51,687	51,551	52,212	53,154	54,145	55,127	56,104	
Existing Resources-No Additions	56,326	56,247	56,080	55,958	55,982	54,719	54,689	54,567	54,477	53,963	53,819	
Interruptible Load	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	
Addition/Retirements By Region For Price Sensitive Scenario												
Northern California												
Additions	0	0	877	2,056	0	0	0	1,667	0	0	0	**4,600**
Retirements	0	0	0	(430)	0	0	0	0	0	0	0	**(430)**
3												
Additions	0	0	1,239	528	0	0	0	0	945	416	0	**3,128**
Retirements	0	0	0	(326)	0	0	0	0	(676)	0	0	**(1,002)**
Southern California												
Additions	0	0	722	625	0	0	0	0	1,040	625	0	**3,012**
Retirements	0	0	0	(634)	0	0	0	0	0	0	0	**(634)**
San Diego												
Additions	0	0	2	0	0	0	0	1,377	0	0	0	**1,379**
Retirements	0	0	0	0	0	0	0	(710)	0	0	0	**(710)**
Net CAL-ISO Capacity Additions	0	0	2,840	1,819	0	0	0	2,333	1,309	1,041	0	**9,342**
Existing Resource Plus Net Additions	56,326	56,247	58,920	60,617	60,641	59,378	59,348	61,559	62,778	63,305	63,161	
*** Margins Over Load With Net Additions**	**10%**	**8%**	**12%**	**13%**	**12%**	**9%**	**8%**	**10%**	**10%**	**9%**	**7%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e. interruptible) load.

Figure II-1
Comparison of Alternative Resource Additions Scenarios
California ISO Control Area

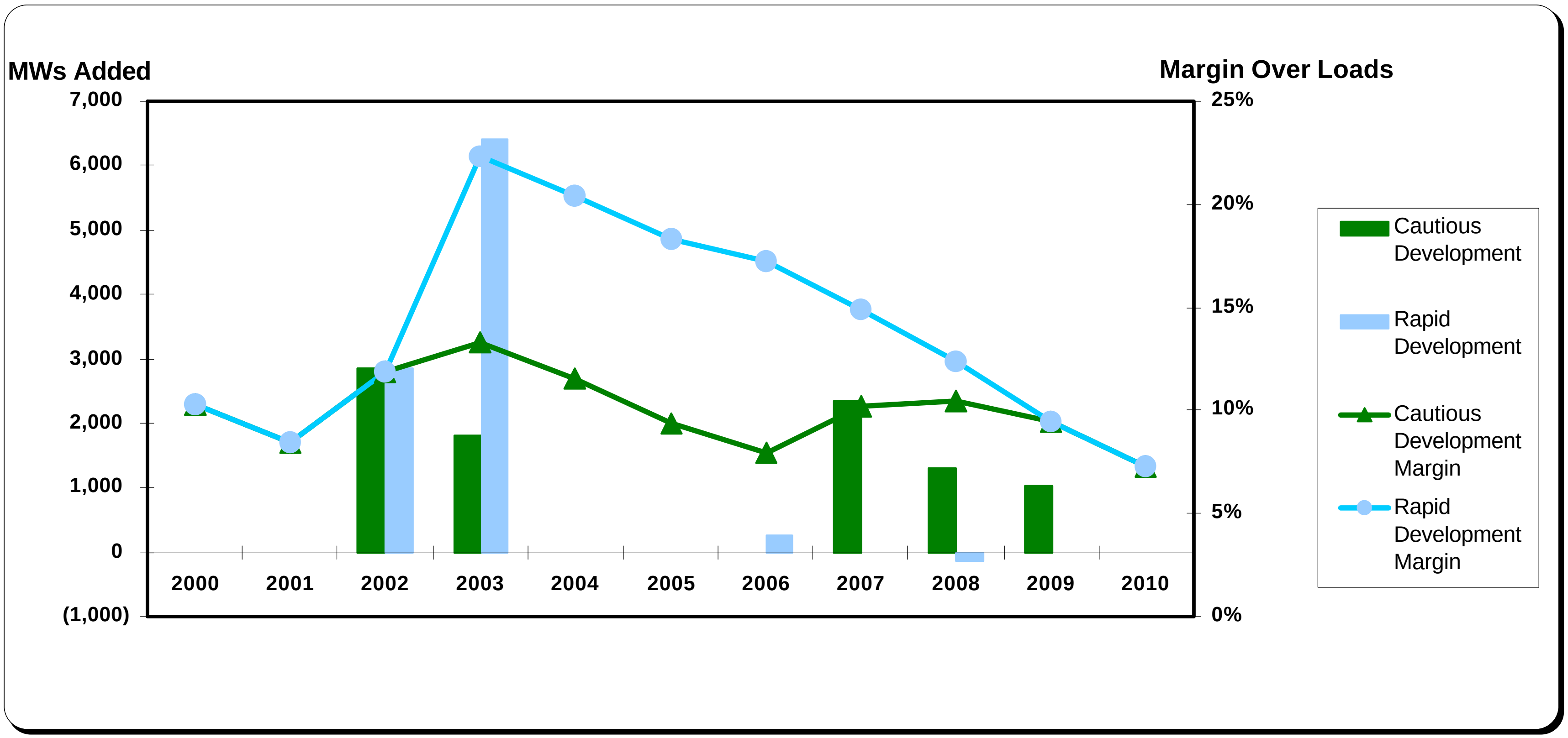


Table II-3
Load Resource Balance for California
Cautious Development Scenario
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
California ISO												
Total Load	48,380	49,122	50,020	50,861	51,687	51,551	52,212	53,154	54,145	55,127	56,104	
Existing Resources-No Additions	56,326	56,247	56,080	55,958	55,982	54,719	54,689	54,567	54,477	53,963	53,819	
Interruptible Load	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	
Net CAL-ISO Capacity Additions	0	0	2,840	1,819	0	0	0	2,333	1,309	1,041	0	**9,342**
Margins Over Load With Net Additions	**10%**	**8%**	**12%**	**13%**	**12%**	**9%**	**8%**	**10%**	**10%**	**9%**	**7%**	
LADWP												
Total Load	6,553	6,584	6,644	6,709	6,742	6,726	6,762	6,825	6,892	6,960	7,033	
Existing Resources-No Additions	9,451	9,451	9,451	9,451	9,451	9,451	9,451	9,451	9,379	9,379	9,379	
Interruptible Load	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	
Net Additions	0	0	10	0	0	0	0	0	0	0	0	**10**
Margin Over Loads With Net Additions	**40%**	**39%**	**38%**	**37%**	**36%**	**37%**	**36%**	**35%**	**32%**	**31%**	**30%**	
Imperial Irrigation District												
Total Load	750	770	791	812	833	854	875	895	915	936	956	
Existing Resources-No Additions	874	874	666	666	666	666	666	666	666	633	633	
Interruptible Load	0	0	0	0	0	0	0	0	0	0	0	
Net Additions	0	0	59	148	0	0	0	0	0	0	0	**207**
Margin Over Loads With Net Additions	**17%**	**14%**	**-8%**	**8%**	**5%**	**2%**	**0%**	**-2%**	**-5%**	**-10%**	**-12%**	
California Total												
Total Load	55,683	56,476	57,455	58,382	59,262	59,131	59,849	60,874	61,952	63,023	64,093	
Existing Resources-No Additions	66,651	66,572	66,197	66,075	66,099	64,836	64,806	64,684	64,522	63,975	63,831	
Interruptible Load	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	
Net Additions	0	0	2,909	1,967	0	0	0	2,333	1,309	1,041	0	**9,559**
Existing Resource Plus Net Additions	66,651	66,572	69,106	70,951	70,975	69,712	69,682	71,893	73,040	73,534	73,390	
*** Margin Over Loads With Net Additions**	**14%**	**12%**	**15%**	**16%**	**14%**	**12%**	**11%**	**13%**	**13%**	**12%**	**9%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e. interruptible) load.

Out-of State Resource Additions

The Multisym™ model, which the staff used to forecast market clearing prices, simulates the generation and transmission of electricity throughout the WSCC. **Figure II-2** depicts the representation of the WSCC in Multisym™. Transfers of electricity on the bulk transmission network within the WSCC contribute to maintaining system reliability throughout the region. One factor that makes these transfers possible is the load diversity between the Northwest, which has its peak demand in the winter, and California and the Southwest, which peak in the summer. Because of the interdependence of these areas for meeting peak season demand, the staff made certain assumptions with respect to generation additions in areas outside of California to ensure that the loads and resources for the WSCC region were in balance.

The staff first gathered information from various sources on planned and proposed generation and retirements in areas outside California.[vi] (A complete listing of these out-of-state projects is provided in **Appendix C**.) Based on this information, the projects were assigned to one of the five categories.

1. Under construction or completed
2. Regulatory approval received
3. Application under review
4. Starting application process
5. Press release only

The staff was able to identify 26,309 MW of new generation planned for the WSCC outside of California. Combined cycle plants fueled by natural gas comprise the majority of the planned generation. **Table II-4** below provides the breakout of this planned generation according to the five categories and the estimated year on-line.

Initially, only projects in the first two categories were added in the model. However, after running the model with just these additions, the model reported unserved energy occurring in certain subregions of the WSCC. To address this problem, generic combined cycle plants were added in these subregions. However, no generic resources were added before 2002.

Figure II-2
Representation of WSCC in Multisym™

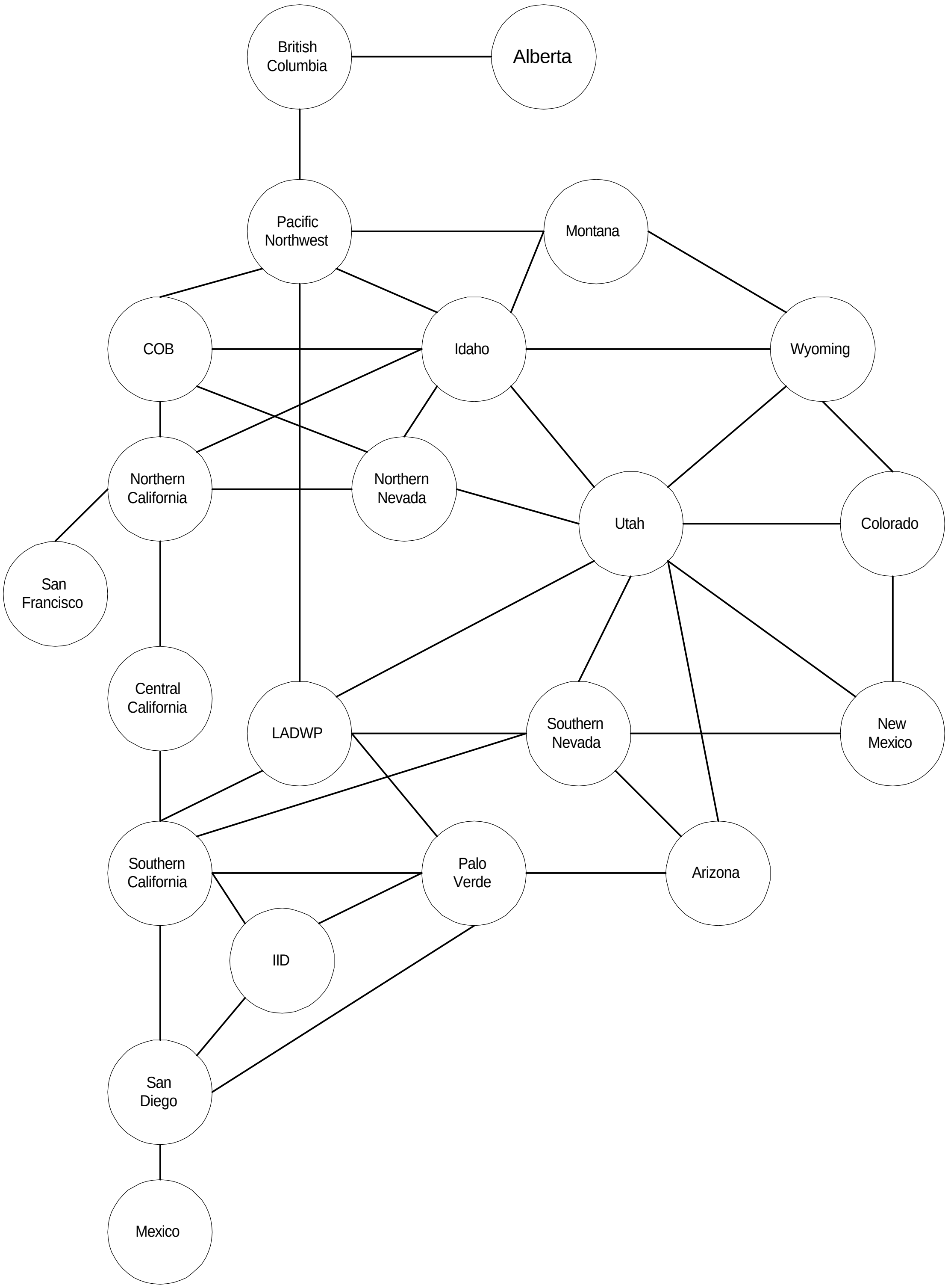


Table II-4
Planned Generation in the WSCC Outside of California
(MW)

Category	Estimated Year of Operation					Total
	1999	2000	2001	2002	2003	
1	806	1,186	2,822	-	250	5,064
2	-	565	1,544	-	-	2,109
3	-	-	-	400	4,294	4,694
4	-	-	30	172	825	1,027
5	-	-	665	3,100	9,650	13,415
Total	**806**	**1,751**	**5,061**	**3,672**	**15,019**	**26,309**

Source: Energy Commission Staff

The criteria staff used for adding generic capacity in a region were based on professional judgement. As a general guideline, the staff added generic resources to a subregion if its planning reserves fell below 6 percent. However, reserves in some areas were allowed to drop below this level. Allowing reserves to drop below 6 percent was done because some areas are currently able to meet peak demand with relatively low reserve margins by relying on purchases of electricity from other regions. The staff also believes that planning reserve margins under competition will be significantly lower than those that prevailed under regulation.

Several factors will contribute to reserves being lower. The primary factors are that there is no guaranteed return for merchant plants and that energy demand with sharp needle peaks may cause a lot of capacity to be idle much of the year. Merchant plant developers will want to have access to the widest possible market to improve their profitability. This factor will translate into an increased reliance on load diversity among regions in the West and an increase in regional transfers of electricity. Plant availability during the peak demand hours should also be greater because these are the hours which will determine whether a generator makes a profit for the year. Demand-side responsiveness should also increase during the high priced peak hours.

Tables II-5 through II-8 provide the load resource balances for each of the four WSCC planning areas and the reserve margins over load after resource additions.

Table II-5
California-Mexico Load Resource Balance
Cautious Development Scenario
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
California												
Total Load	55,683	56,476	57,455	58,382	59,262	59,131	59,849	60,874	61,952	63,023	64,093	
Existing Resources-No Additions	66,651	66,572	66,197	66,075	66,099	64,836	64,806	64,684	64,522	63,975	63,831	
Interruptible Load	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	
Net Additions	0	0	2,909	1,967	0	0	0	2,333	1,309	1,041	0	**9559**
Margin Over Loads With Net Additions	**14%**	**12%**	**15%**	**16%**	**14%**	**12%**	**11%**	**13%**	**13%**	**12%**	**9%**	
CFE-Mexico												
Total Load	1,595	1,690	1,791	1,900	2,015	2,137	2,268	2,407	2,555	2,712	2,879	
Existing Resources-No Additions	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	
Interruptible Load	0	0	0	0	0	0	0	0	0	0	0	
Planned & Proposed Additions	150	100	450	0	0	225	0	0	0	0	0	**925**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	417	0	0	417	0	**833**
Net Capacity Addition	150	100	450	0	0	225	417	0	0	417	0	**1,758**
Margin Over Loads With Net Additions	**-3%**	**-3%**	**17%**	**10%**	**4%**	**8%**	**20%**	**13%**	**7%**	**16%**	**9%**	
California CFE-Mexico												
Total Load	57,278	58,166	59,246	60,282	61,277	61,268	62,117	63,281	64,507	65,735	66,972	
Existing Resources-No Additions	68,041	67,962	67,587	67,465	67,489	66,226	66,196	66,074	65,912	65,365	65,221	
Interruptible Load	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	
Net Additions	150	100	3,359	1,967	0	225	417	2,333	1,309	1,458	0	**11,317**
Existing Resources Plus Net Additions	68,191	68,212	71,196	73,041	73,065	72,027	72,414	74,625	75,772	76,682	76,538	
*** Margin Over Loads With Net Additions**	**13%**	**12%**	**15%**	**16%**	**14%**	**12%**	**11%**	**13%**	**12%**	**12%**	**9%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

Table II-6
Load Resource Balance for Arizona-New Mexico-Southern Nevada
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Arizona-New Mexico-So Nevada												
Total Load	22,189	22,585	22,821	23,368	23,937	24,507	25,072	25,565	26,178	26,765	27,407	
Existing Resources-No Additions	22,369	21,721	22,127	22,227	21,787	21,533	21,430	21,435	21,422	21,390	21,390	
Interruptible Load	(791)	(802)	(812)	(822)	(833)	(844)	(849)	(854)	(854)	(854)	(854)	
Addition/Retirements By Region												
Arizona												
Additions	0	828	0	417	2,120	1,000	0	0	0	0	0	**4,365**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
New Mexico												
Additions	140	0	0	0	0	0	0	0	0	0	0	**140**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	417	0	0	0	0	**417**
So Nevada												
Additions	480	520	0	0	0	0	0	0	0	0	0	**1,000**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	625	417	0	0	0	0	0	0	0	**1,042**
Net Additions	620	1,348	625	834	2,120	1,000	417	0	0	0	0	**6,963**
Existing Resources Plus Net Additions	22,989	23,689	24,720	25,654	27,334	28,080	28,393	28,398	28,385	28,353	28,353	
*** Margin Over Loads With Net Additions**	**0%**	**1%**	**5%**	**6%**	**11%**	**11%**	**10%**	**8%**	**5%**	**3%**	**0%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

Table II-7
Load Resource Balance for Rocky Mountain Region
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Rocky Mtn. Power Region												
Total Load	10,206	10,353	10,540	10,758	11,011	11,193	11,486	11,766	12,050	12,359	12,661	
Total Existing Resources	11,962	11,856	11,806	11,996	11,997	11,997	11,997	11,997	11,997	11,997	11,997	
Interruptible Load	(291)	(291)	(291)	(291)	(292)	(292)	(292)	(292)	(292)	(292)	(292)	
Addition/Retirements By Region												
Colorado												
Additions	565	214	0	240	0	0	0	0	0	0	0	**1,019**
Retirements	0	0	0	(90)	0	0	0	0	0	0	0	**(90)**
Additions For Reliability	0	0	0	0	0	0	0	0	0	480	0	**480**
Wyoming												
Additions	20	20	0	0	0	0	0	0	0	0	0	**40**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
Net Additions	585	234	0	150	0	0	0	0	0	480	0	**1,449**
Existing Resource Plus Net Additions	12,547	12,675	12,625	12,965	12,966	12,966	12,966	12,966	12,966	13,446	13,446	
*** Margin Over Loads With Net Additions**	**20%**	**20%**	**17%**	**18%**	**15%**	**13%**	**10%**	**8%**	**5%**	**6%**	**4%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

Table II-8
Load Resource Balance for Pacific Northwest
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Alberta-BC Hydro- Northwest												
Total Load	63,596	64,264	65,047	65,906	67,286	68,261	69,361	70,084	70,986	71,968	72,328	
Total Existing Resources	76,451	75,682	76,239	77,076	77,162	77,717	77,835	77,835	77,835	77,835	77,819	
Interruptible Load	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	
Addition/Retirements By Region												
Alberta												
Additions	883	38	675	0	0	0	0	0	0	0	0	**1,596**
Retirements	0	0	(72)	(574)	0	0	0	0	0	0	0	**(646)**
Additions For Reliability	0	0	0	0	480	0	0	480	0	0	480	**1,440**
BC Hydro												
Additions	43	38	250	0	0	0	0	0	0	0	0	**331**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
Northwest												
Additions	7	1,220	0	720	0	0	0	0	0	0	0	**1,947**
Retirements	(11)	0	0	0	0	0	0	0	0	0	0	**(11)**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
Net Capacity Addition Alberta-BCHydro- NW	922	1,296	853	146	480	0	0	480	0	0	480	**4,657**
Existing Resource Plus Net Additions	77,373	77,900	79,310	80,293	80,859	81,414	81,532	82,012	82,012	82,012	82,476	
*** Margin Over Loads With Net Additions**	**20%**	**20%**	**21%**	**21%**	**19%**	**18%**	**16%**	**16%**	**14%**	**13%**	**13%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

[i] On August 26, 1999, the ISO Board of Governors approved the creation of a new congestion zone between Path 15 and Path 26. This third zone is defined as the central California zone in staff's modeling.

[ii] These included System Impact Studies for the La Paloma Power Project, the Sunrise Cogeneration and Power Project, the Elk Hills Power Project, the Pittsburg District Energy Facility, Delta Energy Center Project, the Morro Bay Power Plant Modernization and the Moss Landing Power Plant Project.

[iii] The reserve margin is the amount of capacity a utility has available in excess of its system peak load, expressed in MW or as percentage of the peak.

[iv] Operating reserves are a combination of the unloaded capacity of plants that are connected to the system and have the ability to respond within ten minutes to changes in demand and capacity not operating but capable of providing power within ten minutes. Control areas dominated by hydro generation capacity have a lower operating reserve requirement closer to 5 percent.

[v] The WSCC is a voluntary organization comprised of major transmission utilities, transmission dependent utilities, and independent power producers/marketers within the western part of the continental U.S. the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California, Mexico. It promotes regional electric service reliability through the development of planning and operating reliability criteria and policies.

[vi] These sources included discussions with state regulatory agencies, energy industry newsletters (Western Energy Update, Power Markets Week, and the California Energy Markets), company web sites, and telephone calls to project developers.

Section III: New Market Entry

In this section, we compare our forecasts of annual MCPs to the annual revenue requirement of a new generator. The comparison provides a first order measure of whether prices are likely to be sufficient to attract new entry at a time when the system needs new generation capacity.

MCPs and system reliability are inextricably linked. To assure reliability, the revenue available from the PX energy market, as well as the ISO ancillary services markets, must be sufficient to sustain at least some of the existing generation infrastructure while attracting the additional generation investment needed to replace aging equipment and match load growth. The long-term price of electricity in a market-driven system should settle at a level just sufficient to pay for additional generation capacity, as it becomes needed. If the market is structured and working properly, electricity prices higher than a new generator's revenue requirement indicate new generation capacity is needed. Prices lower than the level needed to attract new investment should indicate a surplus of generation capacity exists.

Cost of a New Entrant

For new entry to occur, the MCP must be sufficient to recover the generator's fixed costs and variable costs of operation, including fuel costs. Fixed costs include the ongoing operation and maintenance (O&M) costs that are unavoidable, whether the plant operates or not (fixed O&M), plus the revenue that is required to provide a return to the debt and equity capital that finances construction. The cost of financing capital should provide lenders and investors with returns comparable to those available from other investments of similar risk.

The cost of building a new power plant depends on the technology employed and a host of other, often project/location-specific factors. As a majority of the projects proposed in California and the rest of the WSCC during the past two years have been 500 MW gas-fired combined cycle plants, the staff used the revenue requirement for a combined cycle plant as a proxy for the cost of new entry. For comparison purposes, the staff also developed the annual revenue requirement for a combustion turbine. **Table III-1** provides an estimate of the operating and cost characteristics for both a combined cycle and a combustion turbine.

Table III-1
Operating and Cost Assumptions
(Year 2000)

	Combined Cycle	Combustion Turbine
Fixed Costs		
Inputs to Fixed Charge Rate		
Debt/Equity Ratio	60/40	60/40
Return to Equity (post-tax)	17%	24%
Cost of Debt	8%	8%
Investment Recovery Period	30 years	30 years
Fixed Charge Rate (%)	**14.5%**	**18.5%**
Instant Capital Cost ($/kW)	600	360
Fixed O&M ($/kW-yr)	10	5
Variable Costs		
Heat Rate (Btu/kWh)	6,800	9,100
Fuel Cost ($/MMBtu)	2.5	2.5
Fuel Cost ($/MWh)	17	22.8
Variable O&M ($/MWh)	2	3
Total Variable Costs ($/MWh)	**19**	**25.8**

Source: California Energy Commission Staff Estimates

The upper half of **Table III-1** provides the assumptions and inputs used in calculating the revenue a plant needs to cover its annual fixed cost requirements. These costs are the product of the fixed charge rate times the instant capital cost plus fixed O&M. The fixed charge rate itself is determined by the following inputs:

debt/equity ratio,
the cost of debt,
the rate of return on equity,
the investment recovery period,
federal and state income tax rates, and
state sales and property tax rates.[i]

Using the assumptions in **Table III-1** yields a levelized annual fixed cost revenue requirement of $97/kW-yr for a combined cycle plant and $71.6/kW-yr for a combustion turbine.

(Fixed Charge Rate x Instant Capital Cost) + Fixed O&M = Fixed Cost Req.
Combined Cycle (0.145 x $600/kW) + $10/kW-yr = $97/kW-yr
Combustion Turbine (0.185 x $360/kW) + $5/kW-yr = $71.6/kW-yr

The bottom half of **Table III-1** contains the staff's assumptions that determine a new plant's variable operating costs. These include the plant's heat rate, cost of fuel, and variable O&M costs. Using the heat rates and variable O&M costs in **Table III-1** and a year 2000 fuel cost of $2.50/MMBtu[ii], the total variable cost of a combined cycle plant is $19.0/MWh and $25.8/MWh for a combustion turbine.

The annual average MCP that a power plant must receive to recover both its fixed annual revenue requirement and variable operating costs depends upon the amount of electricity it generates. A 500 MW power plant operating at full output level for 90 percent of the hours in the year can spread its fixed costs over 3,942 GWh. It, therefore, requires a lower average MCP to recover its costs than a plant that operates only 60 percent of the time. **Table III-2** indicates the annual average revenue requirement of a combined cycle plant and a combustion turbine operating at various capacity factors.

Table III-2
Annual Average Revenue Requirement
For New Generators at Various Capacity Factors
Year 2000

Capacity Factor (%)	($/MWh) Combined Cycle	Combustion Turbine
100%	30.06	33.90
95%	30.64	34.33
90%	31.29	34.81
85%	32.01	35.34
80%	32.82	35.94
75%	33.75	36.62
70%	34.80	37.40
65%	36.01	38.29
60%	37.43	39.34
55%	39.11	40.57
50%	41.12	42.06
45%	43.58	43.87
40%	46.65	46.13
35%	50.60	49.04
30%	55.86	52.93
25%	63.24	58.36
20%	74.30	66.51
15%	92.73	80.10
10%	129.59	107.28
5%	240.19	188.81

Table III-2 indicates that combined cycle plants, being more efficient but more expensive, have a better chance of recovering their revenue requirements than a combustion turbine if they can run 45 percent of the year or more. For fewer hours, combustion turbines are more cost effective.

Table III-3 shows how the annual average revenue requirement of a new combined cycle plant operating at a 90, 75, and 60 percent capacity factor escalates during the period 2000-2010. The annual average revenue requirement is sensitive not only to the plant's capacity factor but also to the assumptions contained in **Table III-1**. **Table III-4** illustrates how sensitive the revenue requirement of a generator is to small changes in some of the components underlying the plant's fixed and variable costs.

Table III-3
Necessary Annual Average Revenue Requirement
For a Combined Cycle Plant
(Nominal $/MWh)

Year	Capacity Factor		
	90%	75%	60%
2000	$31.3	$33.7	$37.4
2001	$31.9	$34.4	$38.1
2002	$32.3	$34.9	$38.7
2003	$33.4	$36.0	$40.0
2004	$34.5	$37.2	$41.2
2005	$35.6	$38.3	$42.4
2006	$36.7	$39.5	$43.7
2007	$37.9	$40.7	$45.0
2008	$39.1	$42.0	$46.4
2009	$40.5	$43.5	$48.0
2010	$42.0	$45.1	$49.7

Table III-4
Effect of Assumptions on Revenue Requirement
For a Combined Cycle in the Year 2000

Variable	Base Value	Alternative Value	Change in Annual Average Revenue Requirement ($/MWh)		
			90% CF	75% CF	60% CF
Return to Equity	17%	16%	($0.41)	($0.50)	($0.61)
Debt/Equity Ratio	60/40	50/50	$1.31	$1.57	$1.97
Capital Cost	$600	$610	$0.18	$0.22	$0.28
Recovery Period	30 Years	25 years	$0.42	$0.50	$0.63
Heat Rate	6,800MMBtu/kWh	6,700MMBtu/kWh	($0.25)	($0.25)	($0.25)
Gas Price	$2.50/MMBtu	$2.60/MMBtu	$0.68	$0.68	$0.68

Table III-4 shows that the cost of financing a project, the recovery period that the fixed costs are spread over and the fuel costs are factors which will weigh heavily in determining the plant's competitiveness in the market and its profitability. As the table shows, debt structure is highly significant. It can vary considerably among merchant generation firms.

As stated previously, cost parameters may vary by project and location; the fixed and variable cost values shown in **Table III-1** are intended to be representative of those faced by prospective new entrants in California. Variations would occur within the state due to local costs such as land, air emission offsets, water and natural gas. The staff notes that merchant plants which intend to serve California load, but lie outside the State, may have different construction costs and access to cheaper sources of natural gas than plants located within

California. Construction costs may differ in other states due to difference in the costs of land and labor, different requirements with respect to emission control technologies and offsets, and lead times.

Market Risk and the Cost of Capital

The cost of capital is a product of the perceptions of market risk and uncertainty that lenders and investors of capital in new power plants have regarding future market conditions. While a generator can minimize some of its market risk through long-term fuel contracts and contracts for direct sales of electricity to end-users, other sources of market risk are not so easily managed or contained. Some of these sources are described below.

Market-Risk

- The frequency and height of price spikes — periods during which generators can recover a substantial portion of their annual revenue requirements. Even generators with long-term contracts for sale of their output may rely on price spikes for an adequate revenue stream if the spikes affect the indices on which their contract prices are based.

- Development of the demand-side of the market and its effectiveness in moderating price volatility. The demand-side of the market includes demand-side bidding and the response of customers to real-time pricing tariffs, as well as the continuance of demand-side management (DSM) and direct load control management programs.

- The presence of price caps in both energy and ancillary service markets. The imposition of price caps may be necessary in the short term to stabilize the market while it matures; however, in the long term, these caps delay the price signals needed to trigger new plant investment.

Grid Planning Uncertainty

- Uncertainty regarding who will pay the congestion associated with additional generators.

- The mechanisms/process used to determine when upgrades to the transmission system will occur. The grid planning process is of concern to generators who anticipate revenue for alleviating local reliability problems, those who hope to benefit from constraints on imports into the area in which they are located, and those contemplating locating between major load centers and hoping to benefit from increases in transfer capability. A generator that can sell into the California market during the summer and the Northwest in the winter may have a better chance at making a profit. The risk, and associated financing costs, for projects with broad market access should, be lower.

Regulatory Uncertainty

- Changes in environmental regulations at the regional level, and at the national level (e.g., possible environmental legislation arising from the Kyoto protocol). Efforts to reduce greenhouse gas emissions by the 2008-2012 time frame may result in a reduction of coal-fired capacity in the WSCC. Coal represents 25 percent of the generation capacity in the WSCC.
- The pace of restructuring in neighboring states and the rules they adopt can affect the market clearing price in California. Generators located in states that have not restructured are guaranteed recovery of their fixed costs under the regulatory compact. These generators have a competitive advantage which allows them to bid surplus generation into the California market at their incremental cost of production. Also, because restructuring is occurring on a state-by-state basis, there are no uniform rules. Owners of existing plants may be required to divest these plants because of market power concerns. How each state decides to treat stranded asset costs will also influence the competitiveness of existing generators versus new generators.

In sum, building a new power plant is a risky undertaking. As the rest of the WSCC undergoes electricity restructuring and the competitive generation market matures, the uncertainty and risks associated with investment in power plants should diminish. This maturation of the market should translate into lower financing costs.[iii]

Other Revenue Sources

The estimates of the annual average revenue requirement provided in **Table III-2** and **III-3** are based on the assumption that the PX energy market is the sole source of revenue for a new entrant. The ISO's ancillary service markets and reliability must run (RMR) contracts, however, do represent potential sources of additional income for new generators. **Appendix D** of this report provides a detailed description of the ancillary services market and RMR contracts.

Ancillary services revenues may be important for the profitability of some generators and may constitute a larger percentage of revenues in some months, as demonstrated in **Table III-5**.

Table III-5
Monthly Ancillary Service Costs
As A Percent of Monthly PX Energy Costs*

Jan-99	8.1%	Jul-99	8.1%
Feb-99	5.8%	Aug-99	5.3%
Mar-99	7.8%	Sep-99	4.3%
Apr-99	8.5%	Oct-99	4.6%
May-99	9.5%	Nov-99	3.1%
Jun-99	8.7%	Dec-99	1.8%

***Monthly ISO Ancillary Services Cost/Monthly PX Energy Cost
Source: Management Report Overview Presentation for the ISO 2/24/00 Board Meeting

For the period April through December 1999, the ISO reported that ancillary service costs averaged about $1.87/MWh of total system load served, or about 5.6 percent of total market energy costs.[iv] Using historical data to quantify the amount of income that new entrants might expect from the provision of ancillary services would be imprudent, given both the immaturity of the market, which has only been operating since April 1998, and an unseasonably mild summer in 1999. Future revenues are all the more uncertain due to ongoing changes in the rules governing the procurement of ancillary services. Finally, most of the ancillary services require that the generator have unloaded capacity - the exception being when there is more generation than load (downward regulation). If a new market entrant were bidding into the ancillary services market, the revenue would come at the expense of revenue from the energy market.

Reliability Must-Run (RMR) contracts or, more generally, payments to ensure availability to meet local reliability requirements, may provide some new entrants with revenue beyond that earned in the energy and ancillary service markets.[v] RMR contracts are intended to help generators in areas with a local reliability requirement recover a portion of their fixed costs to ensure their availability. The portion of a generator's costs covered under an RMR contract is negotiated and depends in part upon the generator's expected profitability in the PX energy and ISO ancillary services markets. Accordingly, some new plants that are unable to recover their fixed costs from these markets, may, under the terms of an RMR contract, be paid a portion of the difference between the MCP and their revenue requirement.

The ISO has proposed providing a floor payment to attract new generators to areas with local reliability constraints. For example, the ISO would pay new generators locating in such an area the lesser of $25/kW-yr or10 percent of their annual fixed revenue requirement, even if the plant is profitable based on its revenue from the energy and ancillary services markets.[vi] For a new combined cycle plant operating at a 90 percent capacity factor, this floor payment would lower its annual average revenue requirement year by $1.23/MWh.[vii]

The remaining revenue option available to new generators is a negotiated direct sale to an end-user. There is already some evidence that new generators locating in the California market are trying to firm up their expected revenue by directly contracting with end users.

By guaranteeing a portion or all of their revenue through a direct access contract, a generator can reduce their risk and, consequently, their financing costs.

Viability of New Market Entry Under Staff's Scenarios

Staff examined how new combined cycle plants would fare under the staff's two alternative resource scenarios. **Table III-6** compares the annual average MCP under the two resource development scenarios to the estimated annual average revenue requirement of a new combined cycle plant operating at a 90 percent capacity factor from **Table III-3.** The new entrant's revenue requirement has been reduced by 5 percent on the assumption that at least 5 percent of a new market entrant's revenue would come from sources outside of the PX energy market. As **Figure III-1** illustrates, under the staff's resource scenarios, a new market entrant would not be able to cover their annual revenue requirement until 2010.

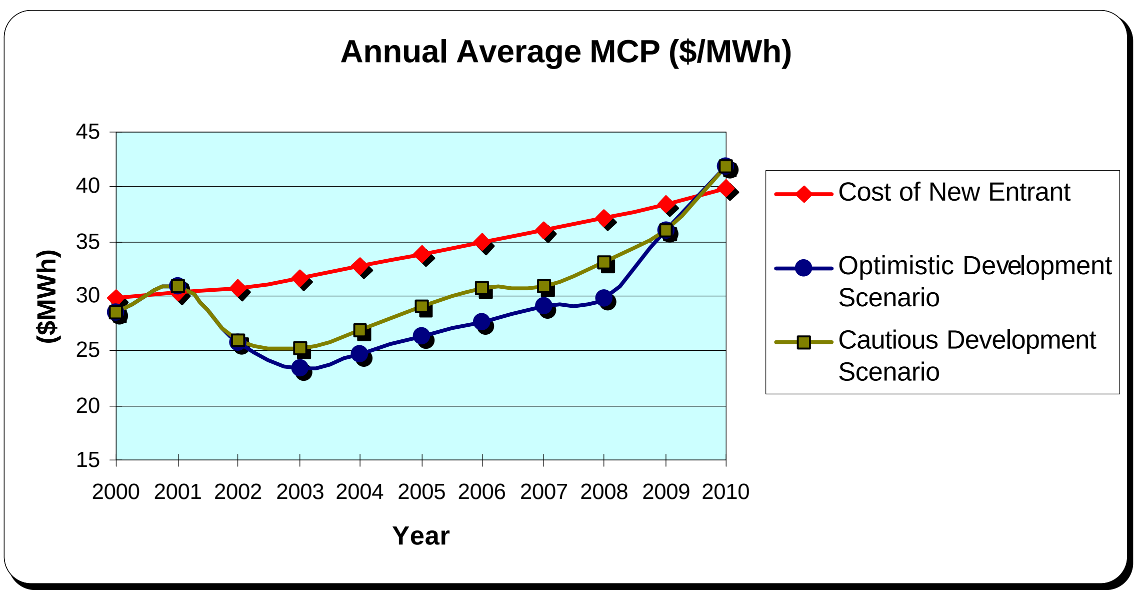
The staff acknowledges that some of the assumptions that went into our modeling of the PX market have both a high degree of uncertainty and a significant influence on market clearing prices. These include our assumption that the generators' bidding behavior in the future will mimic what has occurred historically, and that the nuclear plants will continue to operate. It is also highly unlikely that the timing and number of new generators coming online will occur exactly as portrayed in either scenario.

Despite the uncertainty of these assumptions, we believe that our modeling results illustrate important trends that will have significant consequences to future system reliability. One trend is that future generation resource additions will not occur in a smooth, even manner, but will more likely occur in a cyclical pattern resulting in periods of excess and lean generation capacity. MCPs will respond accordingly, fluctuating in a cyclical pattern as well. This cyclical pattern of development will occur primarily because the profitability of the new generators depends in large part on the prices they are able to get during summer peak demand season. The staff's modeling indicates that MCPs during the summer peak demand season will not reach a level to support new entry until reserve margins drop below the levels usually regarded as necessary for reliable service.

Table III-6
Comparison of Revenue Requirement of a New Market Entrant To Resource Development Scenarios Annual Average MCPs

Year	Optimistic Development Scenario ($/MWh)	Cost of New Entrant ($/MWh)	% Diff	Cautious Development Scenario ($/MWh)	Cost of New Entrant ($/MWh)	% Diff
2000	28.5	29.7	-4%	28.5	29.7	-4%
2001	31.0	30.3	2%	31.0	30.3	2%
2002	25.9	30.7	-16%	25.9	30.7	-16%
2003	23.4	31.7	-26%	25.3	31.7	-20%
2004	24.8	32.8	-24%	26.9	32.8	-18%
2005	26.3	33.8	-22%	29.1	33.8	-14%
2006	27.7	34.9	-21%	30.7	34.9	-12%
2007	29.1	36.0	-19%	31.0	36.0	-14%
2008	29.9	37.1	-19%	33.2	37.1	-11%
2009	36.0	38.5	-7%	36.0	38.5	-7%
2010	41.9	39.9	5%	41.9	39.9	5%

Figure III-1
Comparison of Revenue Requirement of a New Market Entrant To Resource Development Scenarios Annual Average MCPs



This pattern of periodic cycles of excess and under capacity is typical of most capital intensive industries. Excess production capacity in most competitive industries, however, is undesirable because it depresses prices and makes it more difficult for all competitors within that industry to make a profit.

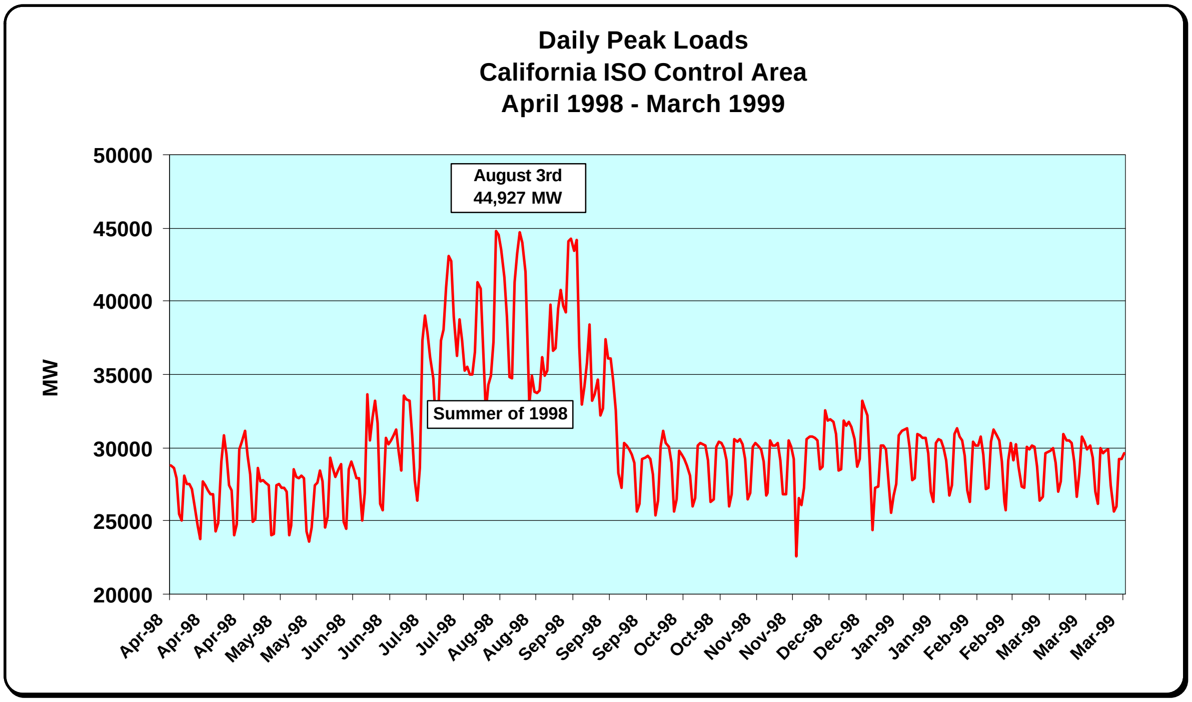
At the time of peak demand, which may last for only a few hours every year, the minimum reserve capability to maintain system reliability is 7 percent.[viii] For most hours of the year, a rather substantial amount of production capacity is not being used. **Table III-7** and **Figure III-2** illustrate this point. **Table III-7** provides the 1998 monthly operating and planning reserve margins over firm loads[ix] for the California-Mexico reliability region of the WSCC. **Figure III-2** depicts the ISO daily loads for one year.

Table III-7
California-Mexico Power Area Actual Monthly Margins for 1998

Month	Jan	Feb	Mar	Apr	May	Jun
Firm Peak Demand (MW)	36,691	35,885	35,561	37,334	33,886	41,909
(Available Capacity - Monthly Peak) (MW)	9,840	11,157	9,300	13,839	15,475	14,224
Operating Margin Over Firm Loads	**26.8%**	**31.1%**	**26.2%**	**37.1%**	**45.7%**	**33.9%**
MW Unavailable (Inoperable, Forced Out, Maintenance)	8,170	8,110	10,217	5,094	4,569	1,959
Planning Margin Over Firm Loads	**49.1%**	**53.7%**	**54.9%**	**50.7%**	**59.2%**	**38.6%**
Month	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Firm Peak Demand	49,857	54,586	53,423	40,667	35,982	38,304
Margin Over Firm Loads - MW (Available Capacity – Monthly Peak)	6,616	4,323	4,480	12,327	15,880	12,993
Operating Margin Over Firm Loads	**13.3%**	**7.9%**	**8.4%**	**30.3%**	**44.1%**	**33.9%**
MW Unavailable (Inoperable, Forced Out, Maintenance)	1,549	716	537	3,293	4,739	4,871
Planning Margin Over Firm Loads	**16.4%**	**9.2%**	**9.4%**	**38.4%**	**57.3%**	**46.6%**

Source: Western Systems Coordinating Council, "10-Year Coordinated Plan Summary 1999-2008," October 1999.

Figure III-2



The problem with relying on summer peak demand prices to signal when new entry will occur is that it is largely dependent on weather. The past two summers illustrate that summer demands can fluctuate greatly from one year to the next. In 1998, there were 120 hours when the California ISO peak loads were over 40,000 MW. In 1999, the ISO's loads were over 40,000 MW for only 48 hours.[x] And, as the demand market matures, it is in the highest price hours that we expect to see demand elasticity to take hold.

To attract new market entry, MCPs during the summer peak demand season will have to reach a level high enough to compensate for all the low prices that prevail during most of the year because of an excess of capacity. The staff's modeling indicates that MCPs will only reach that level when the reserve margins during the summer are below the level needed to ensure reliable service.

Any reduction in reliability due to declining reserve margins is arguably a transitional market problem arising from the current inability of consumers to respond to real-time prices. If consumers are willing to pay high prices for energy during peak hours, MCPs should be sufficiently high so as to ensure reliable service. If consumers react to high prices by reducing consumption, declining peak loads will offset the relative absence of generation capacity.

Certainly, if all of the plants in the staff's scenario analysis come on line supply adequacy will not be a problem. However, the staff believes that developers will be closely watching MCPs to see how the prices respond to new entry. If MCPs in 2002 behave in a manner consistent with the results of the staff's modeling as a result of new capacity additions, subsequent additions could be even fewer and more spread out than the additions assumed in the staff's cautious development scenario.

Future Work

The staff recognizes that in the new competitive electricity market, reliability is no longer a matter of new generation capacity being built to meet a forecasted level of demand plus a reserve requirement. Both supply- and demand-side markets need to be developed to ensure a reliable electricity system. In order for these markets to develop there must be clear price signals that indicate what consumers are willing to pay for reliability. Deregulation, however, is still in its infancy in California and the rest of the WSCC. Market imperfections are still being identified and solutions implemented so that both new power plant developers and electricity consumers receive accurate market signals and, from the consumer's standpoint, have the capability to respond to them. In future studies, the staff intends to investigate the impact of greater demand-side market responsiveness in more detail.

In upcoming studies, staff will assess the impact of dry hydroelectric conditions, retirement of older units, and potential demand-side initiatives to reduce summer peaks.

[i] Federal and State marginal income tax rates are 35 percent and 11 percent, respectively; state sales tax rate is 7.5 percent, state property tax rate is 1 percent. Other factors that influence the fixed charge rate are the federal and state depreciation schedules used.

[ii] See Appendix A for natural gas price forecast.

[iii] A drop in the required return on equity from 17 percent to 12 percent would lower the annual revenue requirement in 2001 of a new combined cycle plant, operating at a 90 percent capacity factor, from $31.29/MWh to $29.29/MWh, a decrease of six percent.

[iv] Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 5.

[v] Local reliability constraints determine the amount of an area's load that must be met by local generation. For example, the San Francisco peninsula has a local reliability requirement that specifies that 50 percent of the area's peak demand be met with local generation.

[vi] California Independent System Operator, *Multi-Year Reliability Must-Run RFP*, June 24, 1999.

[vii] MWh of Generation @ 90 percent Capacity Factor
(500 MW x .9 x 8,760 hrs.) = 3,942,000 MWh
Fixed Cost Revenue Requirement without ISO incentive payment
($97/kW-yr x 500 MW x 1000)/3,942,000 MWh = $12.30/MWh
Fixed Cost Revenue Requirement with ISO incentive payment
(($97/kW-yr - $9.7/kW-yr) x 500 MW x1000)/3,942,000MWh = $11.07/MWh
Reduction in Fixed Cost Revenue Requirement
($12.30/MWh - $11.07/MWh) = $1.23/MWh

[viii] Under regulation, utilities typically built out their systems to ensure a planning reserve of around 13 percent. This figure allowed them to cover contingencies such as forced outages and forecast error.

[ix] Firm load excludes the demand of customers who receive electricity under an interruptible load tariff.

[x] Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 2.

Endnotes

1. All MCPs referred to in this report are for the PX's hourly day ahead unconstrained market and unweighted by load.

2. Until March 2002, California's investor-owned utilities (PG&E, SCE, and SDG&E) must buy from and sell all of their generation through the California Power Exchange (PX), which will auction electric power demand and supply. Other market participants — such as independent power producers (IPPs), municipal generators, and utilities located outside of California, aggregators, etc. — have the option of buying from, or selling electricity through the PX or selling directly to a customer without going through the PX.

3. The MCPs from the staff's two scenarios were outputs of the Multisym™ model, a licensed product of Henwood Energy Services Inc. Multisym™ emulates the hourly bidding market of the California PX, as well as the commitment and dispatch of generators and the transmission of electricity throughout the WSCC reliability region.

4. See Appendix D, "Hourly MCP Scaling Methodology," in 1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues, California Energy Commission, December 1998, Publication No. 300-98-015.

5. On August 26, 1999, the ISO Board of Governors approved the creation of a new congestion zone between Path 15 and Path 26. This third zone is defined as the central California zone in staff's modeling.

6. These included System Impact Studies for the La Paloma Power Project, the Sunrise Cogeneration and Power Project, the Elk Hills Power Project, the Pittsburg District Energy Facility, Delta Energy Center Project, the Morro Bay Power Plant Modernization and the Moss Landing Power Plant Project.

7. The reserve margin is the amount of capacity a utility has available in excess of its system peak load, expressed in MW or as percentage of the peak.

8. Operating reserves are a combination of the unloaded capacity of plants that are connected to the system and have the ability to respond within ten minutes to changes in demand and capacity not operating but capable of providing power within ten minutes. Control areas dominated by hydro generation capacity have a lower operating reserve requirement closer to 5 percent.

9. The WSCC is a voluntary organization comprised of major transmission utilities, transmission dependent utilities, and independent power producers/marketers within the western part of the continental U.S. the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California, Mexico. It promotes regional electric service reliability through the development of planning and operating reliability criteria and policies.

10. These sources included discussions with state regulatory agencies, energy industry newsletters (Western Energy Update, Power Markets Week, and the California Energy Markets), company web sites, and telephone calls to project developers.

11. Federal and State marginal income tax rates are 35 percent and 11 percent, respectively; state sales tax rate is 7.5 percent, state property tax rate is 1 percent. Other factors that influence the fixed charge rate are the federal and state depreciation schedules used.

12. See Appendix A for natural gas price forecast.

13. A drop in the required return on equity from 17 percent to 12 percent would lower the annual revenue requirement in 2001 of a new combined cycle plant, operating at a 90 percent capacity factor, from $31.29/MWh to $29.29/MWh, a decrease of six percent.

14. Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 5.

15. Local reliability constraints determine the amount of an area's load that must be met by local generation. For example, the San Francisco peninsula has a local reliability requirement that specifies that 50 percent of the area's peak demand be met with local generation.

16. California Independent System Operator, Multi-Year Reliability Must-Run RFP, June 24, 1999.

17. MWh of Generation @ 90 percent Capacity Factor
    (500 MW x .9 x 8,760 hrs.) = 3,942,000 MWh
    Fixed Cost Revenue Requirement without ISO incentive payment
    ($97/kW-yr x 500 MW x 1000)/3,942,000 MWh = $12.30/MWh
    Fixed Cost Revenue Requirement with ISO incentive payment
    (($97/kW-yr - $9.7/kW-yr) x 500 MW x1000)/3,942,000MWh = $11.07/MWh
    Reduction in Fixed Cost Revenue Requirement
    $12.30/MWh - $11.07/MWh) = $1.23/MWh

18. Under regulation, utilities typically built out their systems to ensure a planning reserve of around 13 percent. This figure allowed them to cover contingencies such as forced outages and forecast error.

19. Firm load excludes the demand of customers who receive electricity under an interruptible load tariff.

20. Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 2.

21. For a more detailed description of the staff's gas price forecast see, "Staff's Preliminary Natural Gas Price and Production Forecast: Assumptions and Results" on the Commission Web Site at www.energy.ca.gov/naturalgas/1999-11-16_GAS_BASECASE.PDF

22. 1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues, Staff Report, California Energy Commission, December 1998, CEC Publication No. P300-98-015. Also available at the Commission's Web Site. (www.energy.state.ca.gov/electricity).

23. Ibid

24. Ibid, Appendix D, Page 43.

25. In some cases, preferred generator dispatch schedules may not be a matter only of preference. Physical design of a package of generating plants may preclude them from operating or responding to operational commands individually.

26. At this point, suppliers and purchasers also include any bids to supply ancillary services.

27. See discussion of congestion below.

28. A minimum contract unit is for delivery of a one MW of energy for sixteen hours a day during a month. This translates into either 400 or 416 MWh/month (16 hrs* 25 days or 26 days = 400 MWh or 416 MWh).

29. See Replacement Reserves and Automated Generation Control below. Major or sustained deviations from schedule may be substantial enough that these plants cannot compensate without compromising regulating margins, necessitating an additional market to compensate for these larger deviations from schedule.

30. In this context, "adequate" means within standards set by the WSCC.

31. Transmission system equipment—such as shunt capacitors, can sometimes be used to maintain voltage and reactive power; however, in some cases, the use of non-generation equipment is impractical or cost-prohibitive.

32. Expected software enhancements will eventually allow other generators to compete to provide these services.

Appendix A: Preliminary 1999 Fuels Report Gas Price Forecast

This appendix provides the natural gas prices used in the 2000 MCP forecast along with a comparison to the gas prices used in the staff's December 1998 MCP forecast. A brief discussion of the methodology underlying the development of the gas prices is also provided.[i]

Natural Gas Prices for the Electricity Generation Sector

Table A-1 contains the forecast of the price of natural gas to the electricity generation sector in nominal dollars and constant 1998 dollars per million Btu for each of the natural gas service areas in California. The price includes transportation charges.

Table A-1
California Energy Commission
Preliminary FR99 Gas Price Forecast
(November 22, 1999)

	Nominal $/MMBtu				Deflators	1998 $/MMBtu				
YEAR	PG&E	SCG	SDG&E	COOL-WATER	Feb-99	YEAR	PG&E	SCG	SDG&E	COOL-WATER
1998	2.57	2.89	2.75		1.0000	**1998**	2.57	2.89	2.75	
1999	2.65	2.66	2.84		1.0181	**1999**	2.60	2.61	2.79	
2000	2.54	2.48	2.77	2.34	1.0385	**2000**	2.45	2.39	2.66	2.26
2001	2.58	2.51	2.80	2.37	1.0623	**2001**	2.43	2.36	2.64	2.23
2002	2.58	2.53	2.84	2.40	1.0864	**2002**	2.38	2.33	2.61	2.21
2003	2.69	2.65	3.02	2.49	1.1101	**2003**	2.42	2.39	2.72	2.25
2004	2.79	2.77	3.12	2.60	1.1389	**2004**	2.45	2.43	2.74	2.29
2005	2.89	2.88	3.23	2.70	1.1587	**2005**	2.49	2.49	2.79	2.33
2006	3.00	3.00	3.34	2.80	1.1865	**2006**	2.53	2.53	2.82	2.36
2007	3.12	3.11	3.48	2.91	1.2162	**2007**	2.56	2.56	2.86	2.40
2008	3.24	3.22	3.61	3.03	1.2482	**2008**	2.60	2.58	2.89	2.43
2009	3.38	3.37	3.76	3.15	1.2830	**2009**	2.63	2.62	2.93	2.46
2010	3.52	3.52	3.89	3.29	1.3209	**2010**	2.66	2.66	2.95	2.49
2011	3.68	3.68	4.06	3.45	1.3623	**2011**	2.70	2.70	2.98	2.53
2012	3.85	3.86	4.26	3.62	1.4061	**2012**	2.74	2.75	3.03	2.57
2013	4.04	4.06	4.47	3.79	1.4529	**2013**	2.78	2.80	3.08	2.61
2014	4.25	4.28	4.70	3.97	1.5022	**2014**	2.83	2.85	3.13	2.64
2015	4.47	4.52	4.95	4.18	1.5562	**2015**	2.87	2.90	3.18	2.68
2016	4.71	4.77	5.20	4.40	1.6150	**2016**	2.92	2.95	3.22	2.72
2017	4.98	5.04	5.48	4.64	1.6782	**2017**	2.97	3.00	3.27	2.76
2018	5.26	5.33	5.79	4.73	1.7464	**2018**	3.01	3.05	3.32	2.71
2019	5.58	5.66	6.05	4.84	1.8211	**2019**	3.06	3.11	3.32	2.66

The preliminary forecast shows a slight increase in the nominal price of natural gas for power generation customers over the next five years. In real dollars, however, a short term decline in the price of gas occurs until 2002. A significant decline in the price of gas in SoCal Gas service area occurs where the forecast shows prices in the year 2000 to be $0.41 per MMBtu lower than the historical 1998 price in nominal dollars. Much of this decline is due to a reallocation of distribution costs among customers by SoCal Gas. By 2005, SoCal Gas prices are comparable to PG&E's. SDG&E's power generation gas prices, however, remain $0.30 to $0.45 per MMBtu higher in nominal dollars than the other service area prices throughout the forecast. The SDG&E forecast assumes that the California Public Utilities Commission continues with its current policy for passing SoCal Gas instate transport costs through to SDG&E. In SoCal's current ongoing rate case proceedings, many parties are arguing for the same electricity generation natural gas rates for SoCal Gas and SDG&E service areas. The outcome of these proceedings could results in gas prices being significantly different from the preliminary forecast.

Figure A-1 below illustrates the natural gas price forecasts for each of the major utility service areas in real dollars. **Figure A-2** shows the same forecasts in nominal dollars.

Figure A-1

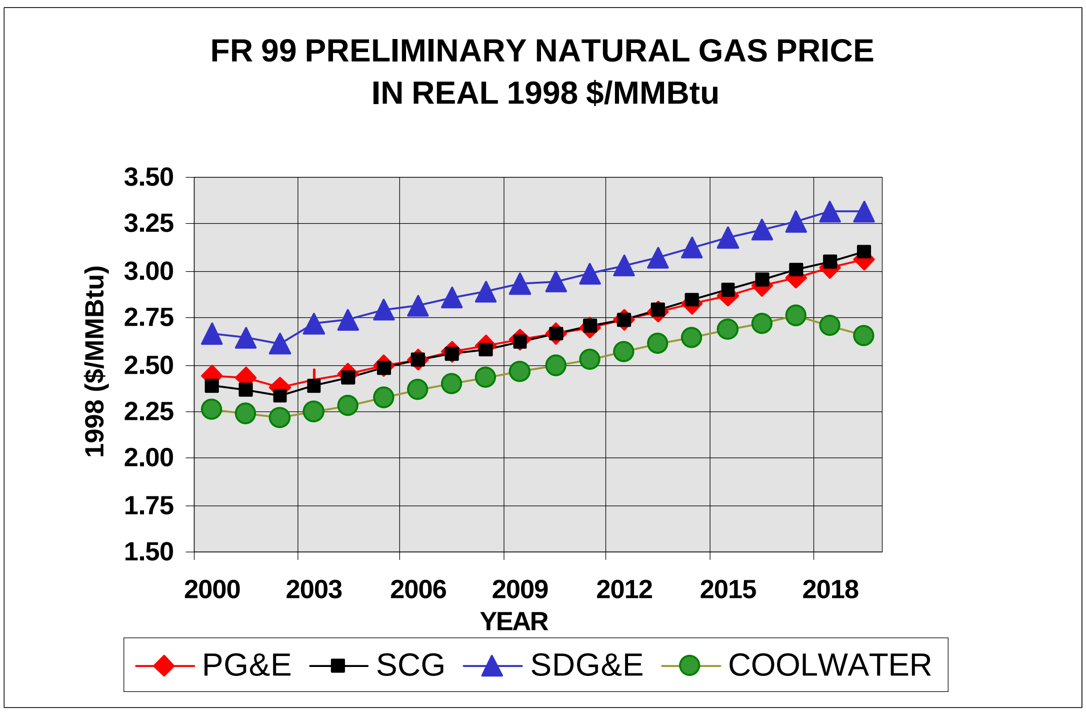
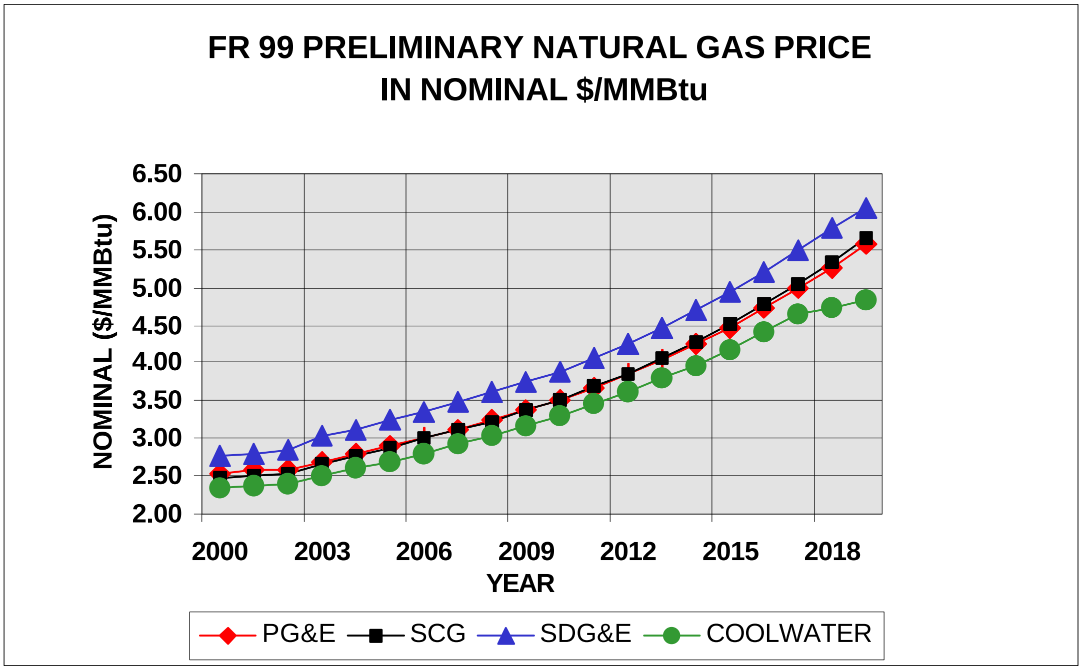


Figure A-2



Comparison to Previous Forecast

Table A-2 provides a comparison of the ***Final Fuels Report (FR 97) Gas Price Forecast***, March 18, 1998 used in the staff's 1998 market clearing price forecast[ii] to the Preliminary ***FR 99*** forecast used in this 2000 market clearing price forecast. The ***FR 99*** forecast prices are significantly higher in the early years compared to the ***FR 97*** forecast. The difference between the two forecasts is attributable to the divestiture of the California investor-owned utility (IOU) fossil fuel-fired power plants.

The methodology underlying the ***FR 97*** forecast assumed that the California IOUs retained ownership of their fossil fuel-fired power plants. The divestiture of these plants affected certain assumptions within the new ***FR 99*** forecast. First, the utilities' revenue allocation formula changed to recover more from electric generation customers. Second, it is assumed that the natural gas supply pool that the divested plants have access to is more expensive than the pool the California IOUs had access to when they owned the plants. When the utilities sold their fossil fuel-fired plants, the remaining contracts for firm interstate gas pipeline capacity were assumed to be no longer applicable.

Table A-2
Comparison of Gas Price Forecasts
Nominal $/MMBtu

Year	PG&E		Change	SCG		Change	SDG&E		Change
	Nov-99	Mar-98		Nov-99	Mar-98		Nov-99	Mar-98	
2000	2.54	2.19	16.1%	2.48	2.17	14.4%	2.77	2.61	6.1%
2001	2.58	2.28	13.1%	2.51	2.29	9.7%	2.80	2.73	2.8%
2002	2.58	2.38	8.4%	2.53	2.40	5.4%	2.84	2.85	-0.5%
2003	2.69	2.50	7.5%	2.65	2.55	4.0%	3.02	2.98	1.6%
2004	2.79	2.62	6.7%	2.77	2.69	2.9%	3.12	3.13	-0.3%
2005	2.89	2.75	5.0%	2.88	2.85	1.2%	3.23	3.28	-1.4%
2006	3.00	2.89	3.8%	3.00	3.00	0.1%	3.34	3.43	-2.6%
2007	3.12	3.03	2.9%	3.11	3.17	-2.0%	3.48	3.61	-3.6%
2008	3.24	3.18	2.0%	3.22	3.38	-4.6%	3.61	3.81	-5.4%
2009	3.38	3.34	1.2%	3.37	3.57	-5.6%	3.76	3.99	-5.9%
2010	3.52	3.51	0.2%	3.52	3.69	-4.7%	3.89	4.14	-5.9%
2011	3.68	3.70	-0.8%	3.68	3.90	-5.7%	4.06	4.36	-6.8%
2012	3.85	3.91	-1.6%	3.86	4.12	-6.4%	4.26	4.58	-7.1%
2013	4.04	4.13	-2.1%	4.06	4.35	-6.7%	4.47	4.82	-7.3%
2014	4.25	4.36	-2.4%	4.28	4.59	-6.7%	4.70	5.06	-7.1%
2015	4.47	4.59	-2.5%	4.52	4.83	-6.6%	4.95	5.31	-6.9%
2016	4.71	4.83	-2.4%	4.77	5.10	-6.4%	5.20	5.59	-6.9%
2017	4.98	5.09	-2.2%	5.04	5.37	-6.1%	5.48	5.86	-6.5%

Gas Price Forecast Methodology

The California Energy Commission's Fuel Resources Office uses the North American Regional Gas (NARG) model to forecast natural gas prices for various market sectors such as electric generation. The NARG model is a generalized equilibrium model that simultaneously solves for supply, demand and price equilibrium for 19 North American supply and demand regions.

Basic inputs to the NARG model include estimates of resource availability, production costs, pipeline capacity and transportation costs, regional demand projections, and other parameters defining market fundamentals. The model also accounts for reserve appreciation over time. The model uses these inputs to determine the California border price of gas. In determining the end-use price for each market sector in the state, the model tracks the costs of distributing and delivering natural gas for each customer class. These costs are added to the California border price to generate the end-use prices for each market sector in each natural gas service region within the state.

During the 2002-2022 forecast horizon, natural gas supplies for California are expected to come from several sources. Natural gas from the Southwest is expected to remain the principal source during the next 20 years, accounting for approximately 45 percent of total statewide requirements. The remainder of the State's gas demand will be met from supplies from the Rocky Mountain region, Canada, and in-state producers. The staff expects border prices to increase 1.7 percent per year from $2.02 per MCF in 2002 to $2.86 per MCF in the year 2022 (prices expressed in constant 1998 dollars). The details on the estimated source of supply and border price are provided in **Table A-3**.

Table A-3
California Border Supply Availability and Price
1999 Preliminary Base Case

Producing Region	1997	2002	2007	2012	2017	2022
Production (TCF):						
California	0.297	0.292	0.358	0.363	0.383	0.401
Southwest	0.885	1.016	1.131	1.159	1.150	1.157
Rocky Mountains	0.232	0.272	0.319	0.341	0.360	0.380
Canada	0.599	0.528	0.573	0.617	0.678	0.731
Total Supply Available to California (TCF)	**2.012**	**2.108**	**2.381**	**2.480**	**2.570**	**2.669**
Price (1998$/MCF)						
California	N/A	2.13	2.30	2.50	2.70	2.91
Southwest	N/A	2.02	2.25	2.45	2.68	2.91
Rocky Mountains	N/A	2.10	2.32	2.52	2.74	2.96
Canada	N/A	1.96	2.13	2.30	2.50	2.71
Average Price at California Border (1998$/MCF)	**N/A**	**2.02**	**2.23**	**2.42**	**2.64**	**2.86**

While the border price of gas is expected to increase over time, the distribution costs drop for all end-use sectors, thus offsetting the commodity price increase and providing for a relatively flat forecast of natural gas prices in real (not adjusted for inflation) dollars. For the core sector (residential, commercial and small industrial customers), the distribution costs drop at a faster rate than the increase in commodity costs. Therefore, core prices decrease slightly in real terms. On the other hand, the noncore sector (large industrial and electric generation customers) see commodity prices rise faster than the distribution costs decline, which provides a slight growth in noncore customer prices over the forecast horizon

[i] For a more detailed description of the staff's gas price forecast see, "Staff's Preliminary Natural Gas Price and Production Forecast: Assumptions and Results" on the Commission Web Site at www.energy.ca.gov/naturalgas/1999-11-16_GAS_BASECASE.PDF .

[ii] *1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues*, Staff Report, California Energy Commission, December 1998, CEC Publication No. P300-98-015. Also available at the Commission's Web Site. (www.energy.state.ca.gov/electricity).

Appendix B: MCP Forecast and PX Price Comparisons

This appendix compares the Energy Commission staff's previous Market Clearing Price (MCP) forecast (December 1998) to the actual PX prices of the California electricity market and examines the factors that contributed actual MCPs being significantly different from our forecasted prices.

Comparison of 1998 Forecast to PX Prices

Table B-1 compares the monthly values of the Energy Commission staff's December 1998 MCP Forecast[i] to actual PX prices, from the beginning of the market, April 1998, up through December of 1999.

Table B-1
1998 MCP Forecast vs. Actual PX Prices

1998	PX Actual ($/MWh)	CEC Dec-98 ($/MWh)	1999	PX Actual ($/MWh)	CEC Dec-98 ($/MWh)
Jan	-	-	Jan	21.0	27.5
Feb	-	-	Feb	19.0	24.8
Mar	-	-	Mar	18.8	23.6
Apr	22.6	21.0	Apr	24.0	21.3
May	11.6	20.0	May	23.6	19.9
Jun	12.1	19.2	Jun	23.5	18.4
Jul	32.4	27.3	Jul	28.9	24.8
Aug	39.5	30.1	Aug	32.3	33.1
Sep	34.0	30.5	Sep	33.9	29.8
Oct	26.6	24.8	Oct	47.6	22.7
Nov	25.7	26.0	Nov	37.0	23.7
Dec	29.1	29.0	Dec	29.7	26.7
----------	-------	-------	----------	-------	-------
Average	26.0	25.3	Average	28.4	24.7

The PX monthly prices are the unconstrained average MCP, unweighted by demand. The PX monthly values are calculated as the simple average of all the hours in the month. The Energy Commission forecast is the simple average of the hours in a typical week. For both the PX prices and the staff's forecast, the annual averages are weighted by the days in the month.

The following two figures present the data in **Table B-1** graphically. **Figure B-1A** compares the Energy Commission staff's forecast to the actual PX prices for the year 1998. **Figure B-1B** makes this same comparison for the year 1999.

Figure B-1A

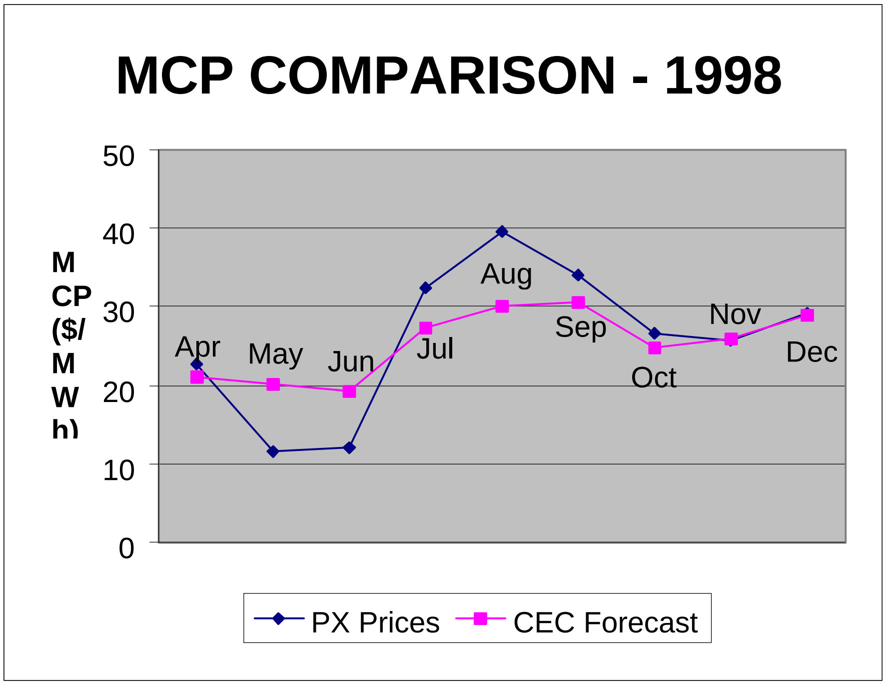
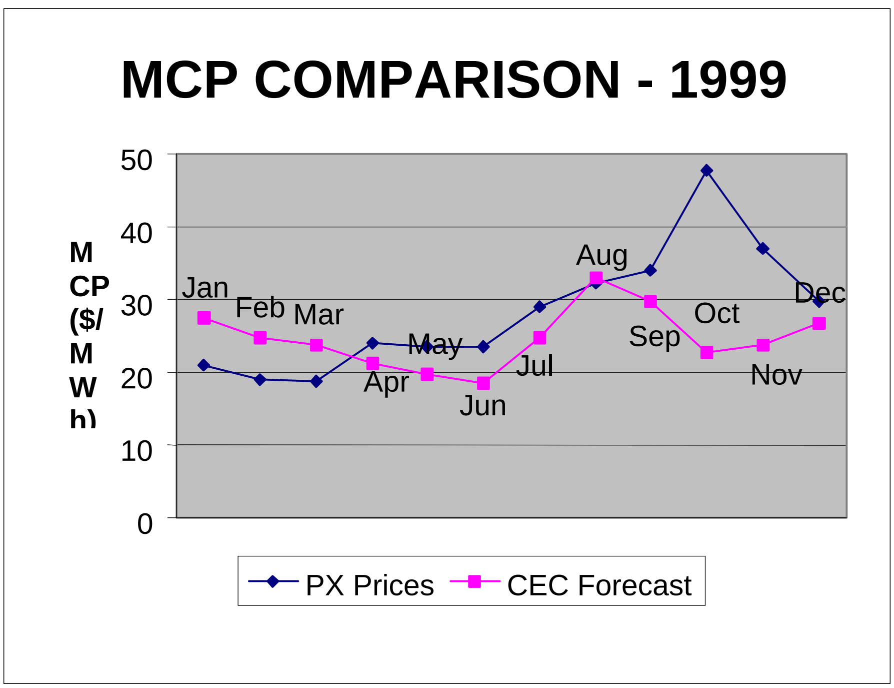


Figure B-1B



The 1998 MCP Forecast is more than 10 percent higher or lower than the actual PX prices for 16 of the 21 months. These differences are largely traceable to the fact that the forecast is for an average year: average temperatures, average hydroelectric generation and average equipment failures. In the real world, there are few – if any – "average" months. In addition, actual monthly natural gas prices often deviate from the Commission's gas price forecast, which further compounds these differences in MCPs. For example, the low spring PX prices reflect the above average hydro conditions that have characterized 1998 and 1999, in some cases aggravated by lower than average temperatures and/or low gas prices. The high summer PX prices typically reflect the higher than expected summer temperatures, often in conjunction with unexpected generation and transmission equipment failures.

Unexpected generation and transmission equipment failures, however, contributed to high prices in the fall of 1999. For the months of October and November of 1998, when conditions were more "average" the staff's forecast was within 1 percent. For these same months in 1999, the PX prices were dramatically higher than the staff's forecast.

The episode on September 30, 1999 serves as a vivid example of atypical conditions. The system experienced a 4,600 MW unexpected deficiency. Peak loads were 1,512 MW higher than expected. The California Oregon Intertie, which consists of three high voltage AC transmission lines connecting California with the Pacific Northwest, was derated due to the proximity of fires at Red Bluff. Diablo Canyon 2 (1100 MW) was down for refueling, and Diablo Canyon 1 was derated (from 1100 MW down to 480 MW) due to tube leaks, which in turn caused a derate of the Path 15 transmission system, which connects northern and southern California. Within one hour, the 756 MW Navajo coal plant tripped off-line. MCPs followed suit and soared.

Forecasting an accurate monthly average MCP is only half of the challenge. It is just as important to be able to forecast hourly values. Since the most important revenue can occur in the on-peak hours, it is important to know what the MCPs are on an hourly basis.

For most months, the hourly comparison is difficult since the monthly average values of the forecast differ significantly from the PX prices. There are three months, however, where the two monthly values were quite close: November and December of 1998 and August of 1999.

Figures B-1C through **B-1E** show the hourly comparison of the staff's forecast to actual PX prices for these three months.

Figure B-1C

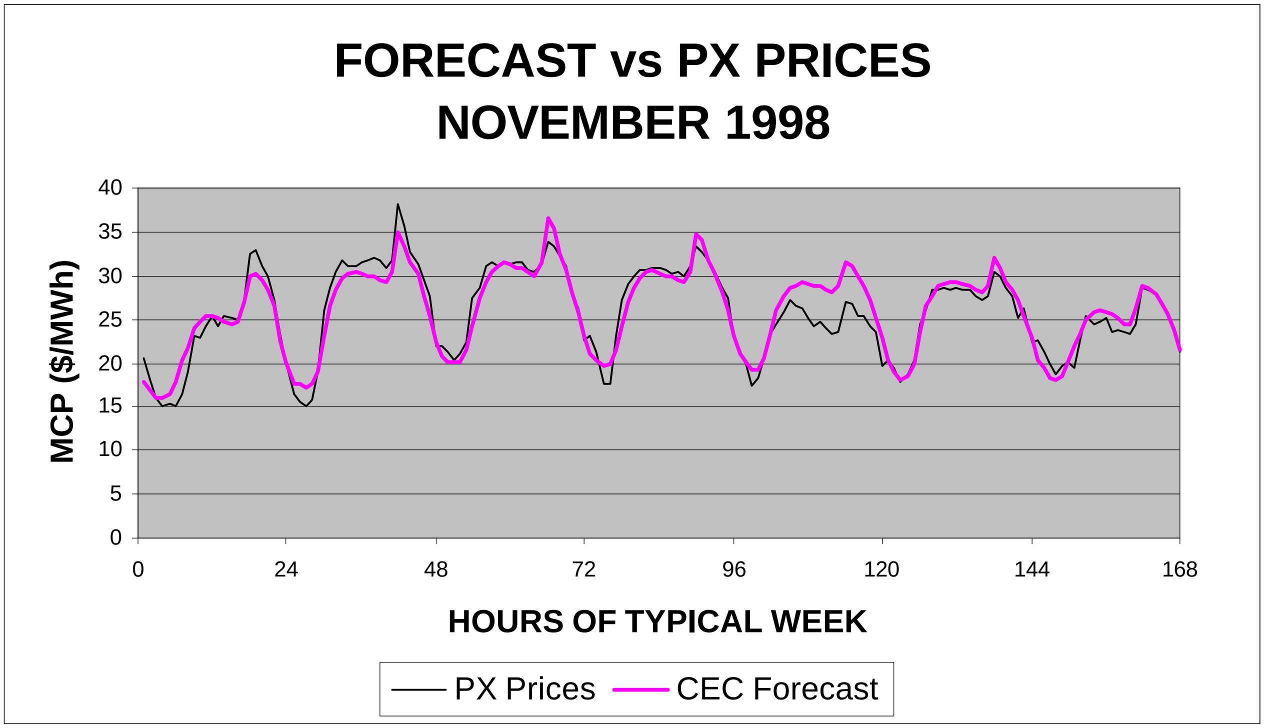


Figure B-1D

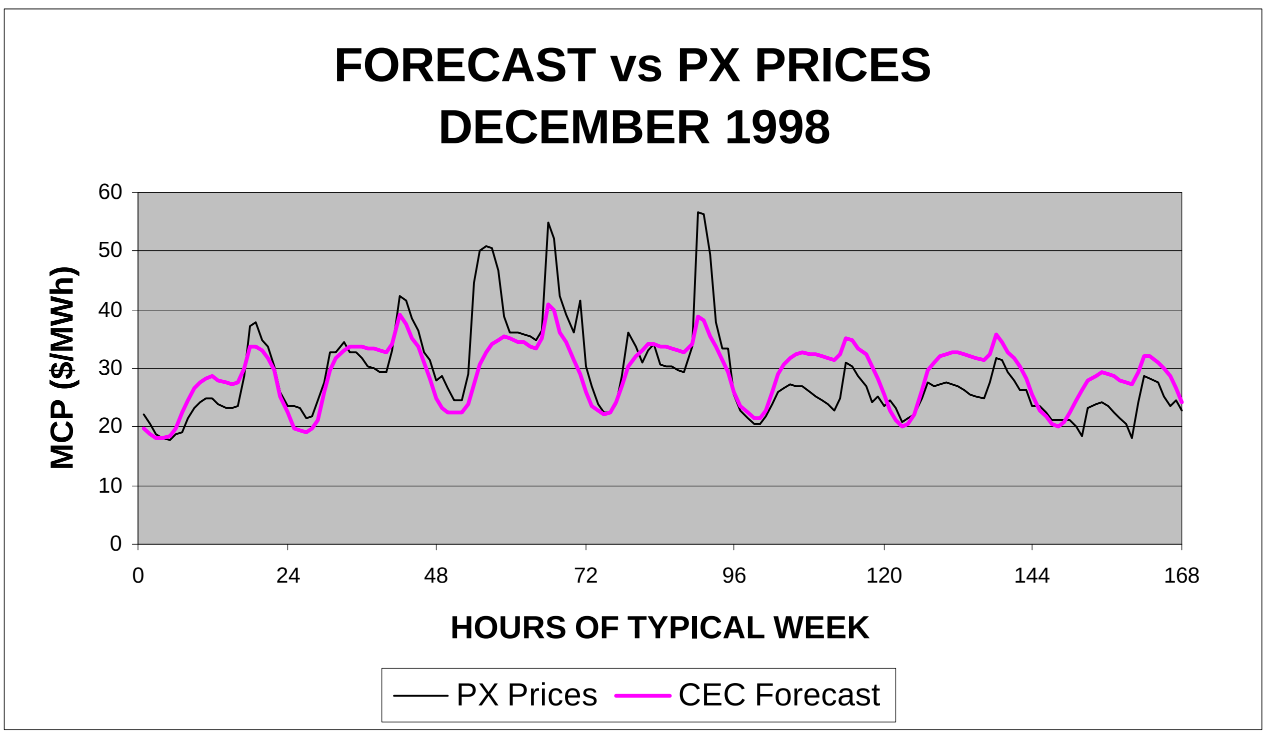
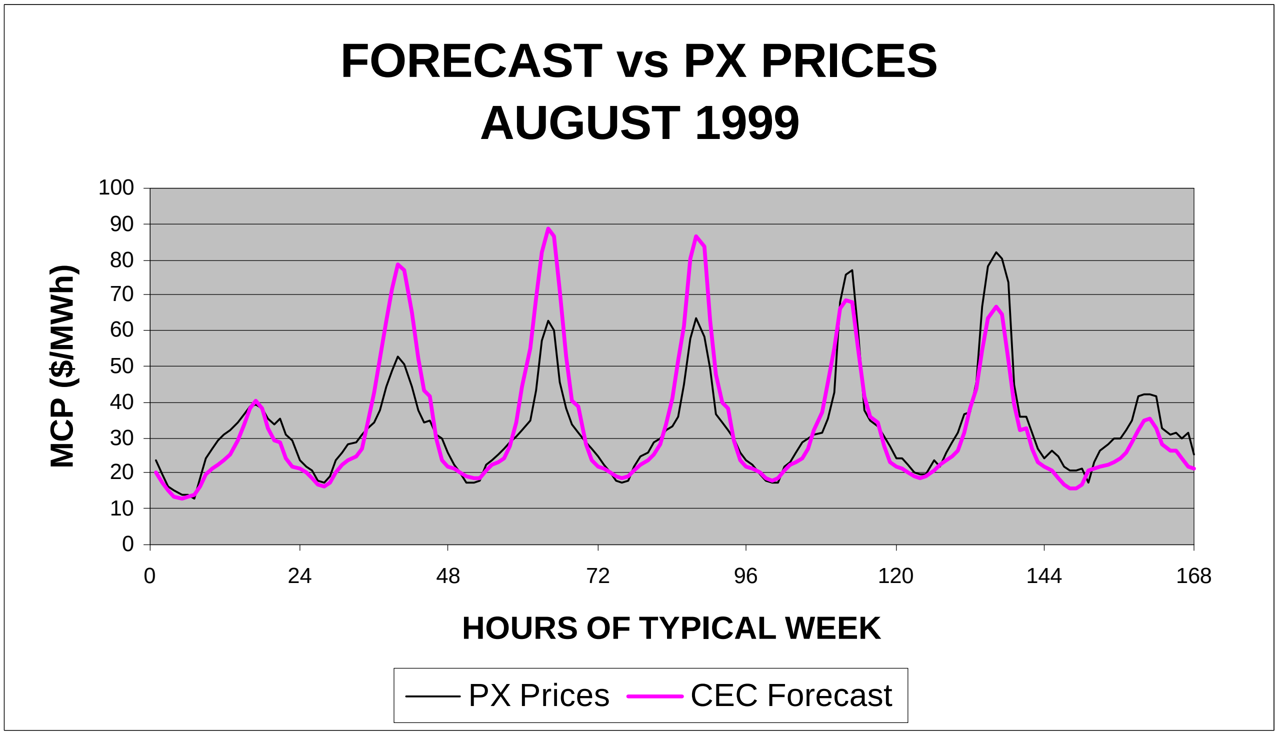


Figure B-1E



The comparison for November of 1998, **Figure B-1C**, is not significant in terms of validating the forecast, as the actual PX data were not only known at the time of the forecast, it was used in developing the shape.[ii] It does serve, however, to convey the staff's conclusion as to what constitutes an acceptable shape for this month.

The comparison for December of 1998, **Figure B-1D,** is more meaningful in terms of validating the forecast methodology as the actual PX data became available after the forecast technical work. This comparison shows that although the staff accurately predicted the monthly value, and in a most general way predicted the shape, it could not—and does not expect to be able to—capture the subtleties of market volatility.

[i] Ibid

[ii] Ibid, Appendix D, Page 43.

The comparison for August of 1999, **Figure B-1E**, is interesting in that the forecast captured the average monthly price and general shape, but it tended to overstate the peaks for Monday, Tuesday and Wednesday. As with December of 1998, the staff does not hope to capture the unexpected volatility of the market, due to such unexpected conditions of abnormal temperature, hydro conditions, and equipment failures.

Appendix C: New Generation Additions Proposed for the WSCC Outside of California

Northwest Power Pool Additions

Facility	State	Unit Type	Fuel Type	# of Units	Capacity (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
Poplar Hill	Alberta		Gas	1	45	January-99	ATCO	Yes	1
Fort Saskatchewan	Alberta				120	December-99	TransAlta	Yes	1
Millennium Cogeneration Ph 1	Alberta	CC	Gas		230	December-99	TransAlta	Yes	1
Joffre	Alberta		Gas		416	September-00	CU Power	Yes	1
Taylor Coulee Shute	Alberta		Hydro		12.5	January-01	Canadian Hydro	Yes	1
Millennium Cogeneration Ph 2	Alberta	CC	Gas		130	December-01	TransAlta	Yes	2
Ft McMurray	Alberta	GT	Gas	2	172	December-02	ATCO/Shell	No	4
Fort Nelson	BC		Gas		45	April-99	BC Hydro/Trans	Yes	1
Stave Falls	BC		Hydro		38	December-00	BC Hydro	Yes	1
Island Cogeneration	BC		Gas		250		Westcoast nrg	Yes	1
Port Alberni	BC		Gas		240		CU Power	Yes	
Rathdrum	ID		Gas	1	270	September-01	Avista		
Blackfeet	MT		Gas		160	June-01	Adair	N/A	5
Carbon County	MT		Coal		2,000	December-03	Composite	No	5
Carlin County	NV				500		Coastal Power		5
Vansycle Ridge	OR	WT	Wind	38	25	March-99	Vestas	Yes	1
Klamath Falls Cogeneration	OR	CC	Gas	2	500	July-01	PacifiCorp	Yes	1
Hermiston	OR	CC	Gas	2	536	December-01	Ida Corp	Yes	2
Newberry	OR		Geothermal		30		NW Geo		
Little Sandy Dam	OR		Hydro		-11		Portland GE	N/A	1
Everett	WA		Gas		248	December-01	FPL Energy	Yes	2
Cowlitz Cogeneration project	WA	CC	Gac	2	250	February-04	Weyerhauser	Yes	2
Satsop	WA	CC	Gas	2	454		Energy Northwest	Yes	3
Sumas 2 Generating Facility	WA	CC	Gas	2	720	December-03	National Energy	Pending	3
Total MW Northwest Area					**7,380.5**				

Status Key: 1- Under construction or completed; 2- Regulatory approval received; 3- Application under review; 4- Starting app process; 5- Press release only

Southwest Power Area (Arizona, New Mexico, Southern Nevada) Additions

Facility	State	Unit Type	Fuel Type	# of Units	Capacity (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
South Point	AZ		Gas		500	May-01	Calpine	Yes	1
Griffith Energy Project	AZ	CC	Gas	2	520	May-01	Duke/PP&L	Yes	1
Desert Basin Generating	AZ		Gas		500	June-01	Reliant	Yes	1
43rd Ave Plant (Phase 1)	AZ	CC	Gas	1	130	August-01	APS/Calpine	Yes	2
43rd Ave Plant (Phase 2)	AZ	CC	Gas	2	500	December-01	APS/Calpine	Yes	2
Arlington Valley	AZ		Gas		500	August-02	Duke	No	5
Redhawk 1	AZ	CC	Gas	1	530	June-03	APS	No	3
Harquahala Generating Station	AZ	CC	Gas		1000	June-03	PG&E	No	3
Kyrene	AZ	CC	Gas		825	January-04	SRP/NRG		4
Gila Bend	AZ	CC	Gas	2	750	June-04	Power Dev Ent	No	5
Redhawk 2	AZ	CC	Gas	1	530	December-04	APS	No	3
Redhawk 3	AZ	CC	Gas	1	530	June-06	APS	No	3
Redhawk 4	AZ	CC	Gas	1	530	December-07	APS	No	3
Santan	AZ	CC	Gas		825		SRP	No	5
Gila River	AZ				2000	December-02	Panda Energy	No	5
El Dorado Energy Project	NV	CC	Gas	2	492	May-00	Sempra/Reliant	Yes	1
Next Generation II	NV		Gas		30	October-01	Next Generation	No	4
Nevada Green Energy Project	NV		Renew		150	December-02	Composite		5
Cobisa-Person	NM	SC	Gas	1	140	May-00	MCN Energy	Yes	1
Belen	NM		Gas		220		Cobisa	No	5
Albuquerque Solar	NM		Solar		5		PSC NM		
Total MW Southwest Area					**11,207.0**				

Status Key: 1- Under construction or completed; 2- Regulatory approval received; 3- Application under review; 4- Starting app process; 5- Press release only

Rocky Mountain Power Area Additions

Facility	State	Unit Type	Fuel Type	# of Units	Output (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
Brush	CO		Gas		60	June-99	BIV Generation	Yes	1
Ray D. Nixon (Phase I)	CO	GT	Gas		70	July-99	Coastal/CSU	Yes	1
CO Wind Farm	CO	WT	Wind		20	August-99	PSC CO	Yes	1
Pawnee Generation Station	CO		Gas	1	265	May-00	Fulton/Coastal	Yes	2
Front Range (Ft Lupton)	CO	CC	Gas	1	164	May-00	KN Power	Yes	2
Valmont	CO		Gas/Coal	N/A	11	December-00	New Centuries	Yes	2
Arapahoe	CO		Gas	2	100	December-00	New Centuries	Yes	2
Fort St. Vrain	CO		Gas	1	235	June-01	PSC CO		
Ray D. Nixon (Phase 2)	CO	CC	Gas		400	December-02	Coastal/CSU	Pending	3
Foote Creek	WY	WT	Wind		41	April-99	PacifiCorp	Yes	1
Arlington Wind Farm	WY	WT	Wind		25	December-00	PSC CO	Yes	2
Black Hills	WY		Coal		80		Black Hills		
Project Orion	‘Multi-state		Gas		5,000		KN Energy	No	5
Total MW Rocky Mtn. Area					**6,471**				

CFE-Mexico Northern Baja Additions

Facility	State	Unit Type	Fuel Type	# of Units	Capacity (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
Cerro Prieto	Mexico		Geothermal		100	July-00	CFE	Yes	1
Rosarito GT	Mexico	GT	Gas		150	July-99	CFE	Yes	1
Rosarito CC	Mexico	CC	Gas		550	July-01	CFE	Yes	1
Rosarito Baja	Mexico		Gas		450	May-02	CFE		5
Total MW CFE-Mexico					**1,250**				

Status Key: 1- Under construction or completed; 2- Regulatory approval received; 3- Application under review;
4- Starting app process; 5- Press release only

Appendix D: Overview of California Electricity Markets

The California PX Energy Markets

The California PX currently runs three markets: the day-ahead, hour-ahead, and block-forward markets. The PX day-ahead market and hour-ahead market discussed below have been operational since the kickoff of competition on April 1, 1998. Together these markets are the primary means that determine California's unconstrained competitive wholesale electricity prices.

PX Day-Ahead Market

The day-ahead market is a forward market for energy and ancillary services that allows wholesale electricity purchasers and suppliers to arrange transactions a day in advance. Advance day-ahead trading activity begins two days before trading day when the ISO publishes system loads and ancillary service requirement forecasts for the ISO-controlled grid. The ISO provides a forecast update the day before trading.

In the PX day-ahead market, participants use PX facilities to submit bids to buy and sell energy for each hour of the following day. The bidding instrument is a 15-segment linear bid curve that must be increasing in the price over the entire quantity offered. These bids are commonly called portfolio bids because they reflect consumption or output from a variety of loads or sources of electricity. Participants specify the sources of electricity later in the process. The PX verifies the bids, ensuring that bidders are capable of completing proposed transactions, then assembles the bid data to generate aggregate supply and demand curves for each hour. The intersection of these curves establishes hourly, unconstrained PX clearing prices.

After establishing the day-ahead PX clearing price, the PX assembles the details of each market participant's bids. A supplier might have particular generation plants in mind for generating, and purchasers may have loads scattered around the State. This information is provided to the PX in initial preferred schedules.[i] Initial preferred schedules are supplemented with schedule adjustment bids that indicate participants' willingness and price to increase or decrease output from a particular generator or reduce consumption.[ii] Participants that do not provide adjustment bids are price takers if any adjustments become necessary.

The PX provides the initial preferred schedules and adjustment bid information to the ISO. From the ISO perspective, the PX is one scheduling coordinator among many providing similar information. The ISO evaluates all the proposed schedules to verify that the transmission system can facilitate the transactions. If congestion occurs, the ISO uses adjustment bids to find the least cost solution to relieve the congestion.[iii] By 4:00 p.m. the day before the trading day, the PX publishes the hourly MCP and the maximum quantities of PX participants for the following day.

PX Hour-Ahead Market

The hour-ahead market provides PX market participants a means to optimize their schedules and reduce a real time imbalance. Hour-ahead market bids are submitted at least two hours before operation and include all pertinent details—that is, no portfolio bids are allowed. Bid iterations are not conducted in the hour-ahead market. The PX determines PX market-clearing schedules and provides this information to the ISO. On January 17, 1999, the PX replaced the hour-ahead market with the day-of market on an experimental basis. However, on November 10, 1999, the PX applied to the Federal Energy Regulatory Commission to make the day-of market a permanent feature. The day-of market consists of three auctions: an auction at 6:00 a.m. for operating hours ending 11:00 a.m. - 4:00 p.m., one at noon for operating hours ending 5:00 p.m. to midnight, and one at 4:00 p.m. for operating hours ending 1:00 a.m. to 10:00 a.m. Like the PX hour-ahead market, the day-of allows no portfolio bids or iterations. The day-of market was introduced because PX hour-ahead market complexity and transactions costs resulted in thin markets, characterized by wild price fluctuations.

Block-Forward Market

The PX block-forward market was introduced in July 1999 to enhance the value and flexibility of PX markets. This market has its own rules, which are enforced by PX Trading Services, a separate division of the PX. Participants in the block-forward market must also be participants in the PX day-ahead market. The block-forward market allows electricity traders to trade electricity contracts for physical delivery in either north of Path 15 (NP 15) or south of Path 15 (SP 15) up to six months in the future. Contracts traded in the block-forward market are standardized contracts for delivery of electricity during the on-peak hours of the month. Actual hours covered are 6:00 a.m. to 10:00 p.m. weekdays and Saturdays but excluding Sundays and holidays.[iv]

As with futures contracts in other commodity markets, block-forward market contracts allow electricity purchasers and suppliers to lock in prices, providing certainty, and a shelter from risk. Block-forward market participants can schedule partial or whole delivery of electricity either bilaterally or through the day-ahead market. If the delivery is scheduled through the day-ahead market, block-forward market participants can also bid electricity originally traded in the block-forward market in the day-ahead market.

ISO Imbalance Markets, Congestion Management, and Ancillary Services

The ISO ensures the reliability of the system through its imbalance market and by procuring ancillary services from generators through long-term contracts and a competitive bidding process. The imbalance market and ancillary services are intended to meet the real-time requirements of the system by balancing electricity supply and demand, maintaining transmission line voltage and facilitating electricity transfers, and providing the necessary reserve of generation capacity to cover certain contingencies.

Real-Time Imbalance Market

Actual electricity use will differ from electricity scheduled in the day-ahead and day-of markets. The ISO retains generating plants that provide backup reserves or electricity to follow small deviations from schedule.[v] For large or sustained deviations from the schedule, the ISO conducts a real-time energy market. Would be real-time market participants submit supplemental bids, which are added to a Balancing Energy *Ex-Post* Pricing (BEEP) stack. The ISO selects generators from the BEEP stack in order of economic merit to provide supplemental energy. In contrast to day-ahead and day-of energy markets, where prices are known in advance of actual market transactions, the price of real time energy may not be available until after the energy has been consumed, hence the term *ex-post* pricing.

During the transition period, the real time energy market has been subject to price caps. On October 1, 1999, the ISO raised the price cap from $250/MW to $750/MW.

Adjustment Bids for Congestion Management

Congestion occurs when unconstrained schedules submitted by scheduling coordinators require more transmission capacity than may exist in certain paths. Congestion may occur within or between congestion zones.

Interzonal Congestion

When congestion occurs between zones, the ISO seeks to reduce electricity flows over the congested path by increasing generation in the congested zone and decreasing generation in the uncongested zone. This is accomplished through adjustment bids submitted by scheduling coordinators to the ISO. The ISO selects an adequate package of the lowest cost incremental (“inc”) bids in the congested zone and the highest value decremental generation (“dec”) bids in the uncongested zone. Dispatched, loads on the congested interzonal transmission line are reduced and congestion is alleviated.

Intrazonal Congestion

Resolving congestion within zones is less simple. Location of generators on the transmission grid is paramount, and there may not be sufficient eligible generators to ensure competitive bidding. If the ISO determines that the generation market on both sides of the congested intra zonal path is workably competitive, then congestion will be relieved using competitively procured inc and dec bids, as is done with interzonal congestion. If either side of the congested path is deemed not to be workably competitive, then the ISO will resolve congestion through a RMR contract. Recent FERC decisions, however, have forced the ISO to rethink its congestion management system.

Cost Recovery

Recovery of the costs of relieving congestion is different for interzonal and intrazonal congestion. For intrazonal congestion, payments to generators that resolve congestion through bids or RMR contracts are totaled and recovered equally from all scheduling coordinators operating in the zone. In interzonal congestion, costs are recovered naturally from the market because the incremental and decremental bids set the MCP for electricity in the congested and uncongested zones, respectively. In cases of interzonal congestion, a congestion payment is made to owners of transmission facilities and firm transmission rights (FTRs). The value of the payment is the difference between the constrained MCPs in the zones on either side of the congested path, scaled to reflect the transmission or FTR owner's share and loading of the congested transmission interface during times of congestion.

Ancillary Services Bids, Day Ahead and Hour-Ahead Market

Ancillary Services are products of generating electricity that play a special role in the delivery of electric service in two ways. First, ancillary services constitute available generation capacity to replace generation lost during contingencies. Second, ancillary services constitute available generation capacity required to respond to variations in electricity demand. Ancillary services have some aspects of public goods. All electricity consumers benefit from ancillary services, but without administrative intervention, no single electricity customer would be likely to schedule and pay for adequate ancillary services.[vi] Most ancillary services support the electrified grid, but one service, black start capability, is important specifically for re-electrification of the grid after major disturbances.

The ISO procures necessary ancillary services through long term contracts and daily bidding. **Table D-1** describes the six ancillary services and the way they are procured by the ISO.

Daily Ancillary Services Bidding

The ISO uses schedules in the day-ahead energy market to determine daily ancillary services requirements. After adjusting ancillary services requirements for those being self provided by scheduling coordinators, the ISO puts ancillary services out to bid. Active scheduling coordinators that wish to compete in the daily ancillary services market may provide terms to the ISO when they submit requests for transmission capacity after the day-ahead energy market closes. The ISO selects the package of ancillary services that satisfy system requirements at the least cost. A similar process is employed for adjusting ancillary services for the day-of market. Ancillary services procured through daily bidding are subject to the same price cap applied to energy prices. As with energy prices, ancillary services prices may fluctuate wildly depending on the need for particular services. **Table D-2** shows the relative costs of the various ancillary services that are traded on a daily basis.

A scheduling coordinator may opt to self provide a part or all of the ancillary services associated with its load rather than rely on ISO procurement. This information would be indicated with schedules submitted in the day-ahead energy market. A scheduling coordinator may save money if its costs are less than the market price charged by the ISO.

Ancillary Services Revenue - Potential Cost Recovery

As a general policy, the ISO charges scheduling coordinators for the ancillary services procured to secure their load. Charges are typically calculated on a trading interval basis by congestion zone. Generators that self-provide some or all of their ancillary services are relieved of their community obligations to ancillary services costs to the extent of their self-provision. There is some variation in calculation of a scheduling coordinator's specific ancillary services' charge due to the nature of some services. Costs of *ex-post* real time energy are included with the ancillary services charge.

TABLE D-1
List of Ancillary Services

Service	Description	How Procured, Paid & Charged
Voltage Support/ Reactive Power	Electricity injections at specific areas in the transmission grid for maintaining reactive capacity and voltage requirements.[vii] The site-sensitive nature of this service may limit competition due to lack of contestants.	**Procured:** Contract (“Voltage Support Agreement”) monthly and real time supplemental on *ex post* basis[viii] **Paid:** $ MW, settled on monthly basis. For *ex post* supplemental, by congestion zone and trading interval **Charged:** By congestion zone and trading interval. Scheduling coordinator’s share of total cost.
Black Start	Restoration of electricity to the ISO-controlled grid by providing the ability to self-start without an external source of electricity.	**Procured:** Contract (“Black Start Agreement”) **Paid:** Contract price in $ MW multiplied by monthly output of black start energy by trading interval and congestion zone. **CHARGED:** Scheduling coordinator’s share of metered demand in trading interval and congestion zone in which service is needed, including costs of testing black start capability.
Regulation/ Frequency	Generation plants equipped with Automated Generation Control (AGC) may be adjusted remotely by the ISO to maintain system frequency and tieline loading within NERC and WSCC operating criteria.	**Procured:** Daily Bidding **Paid:** $/MW, market-clearing price **Charged:** By congestion zone and trading interval. scheduling coordinator’s share of total spin cost by trading interval and congestion zone, minus amount self provided.
Spinning Reserve	Unloaded but spinning (synchronized) generation capacity that is able to be immediately responsive to system frequency and capable of being loaded within ten minutes and holding the load for at least two hours.	**Procured:** Daily Bidding **Paid:** $/MW, market-clearing price **Charged:** by congestion zone and trading interval Subject to Individual Generator Price Ceiling, scheduling coordinator’s share of total Spin cost by trading interval and congestion zone, minus amount
Non-Spinning Reserve	Off-line generating capacity that can synchronize and take load in ten minutes. “Non-spin” has a demand-side equivalent, which is load that can be interrupted in ten minutes. Non-spin generators and load must be capable of providing the service for at least two hours.	**Procured:** Daily Bidding **Paid:** $/MW, market-clearing price **Charged:** By congestion zone and trading interval. scheduling coordinator’s share of total nonspin cost by trading interval and congestion zone, minus amount self provided.
Replacement Reserve	Generation capacity capable of synchronizing to the grid and taking a certain load within sixty minutes of notification and running for two hours, which is set aside to replace energy and ancillary services reserves that have been dispatched. This service may also be provided by load that will curtail within sixty minutes for a period of two hours. Replacement reserve typically makes up for scheduled generation that becomes unavailable.	**Procured:** Daily Bidding **Paid:** $/MW **Charged:** Two components. 1) Actual cost of dispatched replacement reserves billed to each scheduling coordinator in proportion of its imbalance energy as share of total imbalance energy 2) Undispatched replacement reserve billed to all scheduling coordinators in proportion to their respective shares of total cost by trading interval and congestion zone.

Table D-2
Ancillary Service Cost As A Percent of Total A/S Costs

Month	Regulation	Regulation Down	Regulation Up	Spinning Reserves	Non-spinning Reserves	Replacement Reserves
Dec-98	69%			26%	4%	1%
Jan-99	89%			9%	1%	1%
Feb-99	87%			10%	2%	1%
Mar-99	88%			10%	1%	1%
Apr-99	81%			15%	2%	2%
May-99	85%			9%	5%	1%
Jun-99		43%	44%	8%	5%	1%
Jul-99		27%	41%	13%	12%	6%
Aug-99		21%	42%	16%	14%	7%
Sep-99		32%	34%	17%	10%	8%
Oct-99		25%	40%	16%	9%	11%
Nov-99		56%	30%	9%	4%	1%

Source: California ISO

[i] In some cases, preferred generator dispatch schedules may not be a matter only of preference. Physical design of a package of generating plants may preclude them from operating or responding to operational commands individually.

[ii]At this point, suppliers and purchasers also include any bids to supply ancillary services.

[iii] See discussion of congestion below.

[iv]A minimum contract unit is for delivery of a one MW of energy for sixteen hours a day during a month. This translates into either 400 or 416 MWh/month (16 hrs* 25 days or 26 days = 400 MWh or 416 MWh).

[v] See Replacement Reserves and Automated Generation Control below. Major or sustained deviations from schedule may be substantial enough that these plants cannot compensate without compromising regulating margins, necessitating an additional market to compensate for these larger deviations from schedule.

[vi] In this context, “adequate” means within standards set by the WSCC.

[vii] Transmission system equipment—such as shunt capacitors, can sometimes be used to maintain voltage and reactive power; however, in some cases, the use of non-generation equipment is impractical or cost-prohibitive.

[viii] Expected software enhancements will eventually allow other generators to compete to provide these services.

Sample Environmental Externality Valuations

This section provides a sample of externality valuations, for both individual emissions and total externality costs, from a variety of sources. These sources include existing emission-trading markets and externality estimates, made by the CEC and agencies on other states, applied to a range of generic and existing thermal generating plants.

In order to begin quantifying environmental externalities, the slate is not completely blank. There are market values that have been identified for a range of pollutants, based on emission credit and allowance markets that are in effect today. Recent prices for some emission credits are shown in Table 1.

Table 1. Recent Pollutant Market Prices

Emission Market and Credit Type	6/2000	8/2000
Title IV SO2 allowances	146	153
OTC (Ozone Transport Commission) NOx allowances	688	618
World Bank Carbon Fund CO2 offsets	2-5	2-5
South Coast AQMD Values		
NOx RECLAIM trading credits – forward (2003-2010)	9,370	12,310
NOx RECLAIM trading credits – current	14,650	92,050
SO2 RECLAIM trading credits – current	1,850	2,580
NOx emission reduction credits	7,440	7,440
SO2 emission reduction credits	1,670	2,230
VOC (Volatile Organic Compounds) emission reduction credits	830	1,320
PM10 (Particulate Matter <10 microns) emission reduction credits	4,320	4,320

While the CEC reported environmental externality values in the ER94, these values are considered inaccurate today and generally too high. According to the CEC contacts, during 1998 internal discussions involving the CEC and CBEE, CEC staff suggested a significantly lower range of externality values. Their recommendations were based on observations of the South Coast AQMD and other emission trading market prices at that time. However, these values have not been published or circulated publicly.

The 1994 ER94 and 1998 internal values for the CEC environmental adders are based on the emission cost estimates shown in Table 2. Note that the ER 94 values are generally at or above the higher end of the range of values assigned by other states, while the 1998 values are closer to, but generally above, the lower end of this range.

Table 2: Comparative CEC Emission Externality Cost Estimates

Emission Costs $/ton	NOx $/ton	SO2 $/ton	VOC $/ton	PM-10 $/ton	CO2 $/ton
ER 94 Emission Cost	9,120	4,490	4,240	4,610	9
Internal CEC 1998 Emission Cost	1,800	1,780	530	910	9
Other States' Values	850-7500	150-1700	1010-5900	330-4600	1-24

In summary, the recent prices in the South Coast AQMD emission trading prices (shown in Table 1) are still close to the lower (i.e., 1998) values for SO2 and VOCs shown in Table 2. The PM10 prices in Table 1 are closer to the higher (1994) value and the NOx are higher still. The RECLAIM NOx prices have increased recently, and while the prices during 1994-1998 were close to the lower (1998) CEC value, today the prices are even higher than the higher (1994) CEC value.

The remainder of this section provides an indication of how a range of emission costs ($/ton) would translate to energy adders ($/MWh). Emission factors from a typical gas-fired steam turbine generator can be used to estimate the contribution of each pollutant to an overall externality value based on the values listed above for individual pollutants.

The following estimates, however, are not meant to represent definitive estimates of emission valuations. The estimated values are shown by plant for the two sets of CEC emission cost levels shown in Table 2. The plants shown are generic natural gas-fired simple- and combined-cycle units, as well as some existing PG&E natural gas-fired units. For simplicity, the PG&E plant emissions are expressed as the average output from the entire generating facility, rather than isolating emissions and output from each individual generating unit.

Table 3 shows the emission rates for the generic and PG&E plants. The PG&E plant data are based on historical information that includes some residual fuel oil burns. As a result, the SO2 emissions are significantly higher for the PG&E plants than the generic plants, which assume that no fuel oil is used. In the future, we expect that this will be the case, and thus that the SO2 emission rates for the plants listed will be lower.

Table 3: Emission Rates from Generic and PG&E Sample Plants

Emission Rates	NOx Emissions (lb/MWh)	SO2 Emissions (lb/MWh)	VOC Emissions (lb/MWh)	PM-10 Emissions (lb/MWh)	CO2 Emissions (ton/MWh)
Generic CT	2.80	0.20	0.20	0.20	0.80
CT with SCR	0.40	0.20	0.20	0.20	0.80
Steam Turbine	1.70	0.01	0.01	0.03	0.60
ST with SCR	0.25	0.01	0.01	0.03	0.60
CCGT	1.00	0.01	0.07	0.10	0.40
CCGT with SCR	0.15	0.01	0.07	0.10	0.40
Hunters Point	2.27	0.02	0.02	0.04	0.45
Morro Bay	1.18	1.26	0.03	0.15	0.37
Moss Landing	1.45	0.34	0.02	0.06	0.36
Oakland CT	2.31	3.23	0.46	0.46	1.84

Emission rates for Hunters Point, Moss Landing, and Oakland CT are from 1993 recorded data. Morro Bay is from 1995 historic data. Source: PG&E A.96-11-020.

The resulting emissions cost per MWh can be determined by combining the emission rates in Table 3 with the cost scenarios shown in Table 2. The results using the ER 94 values are shown below in Table 4.

Table 4: Sample Emission Costs by Plant - ER 94 Levels

ER 94 Cost	NOx $/MWh	SO2 $/MWh	VOC $/MWh	PM10 $/MWh	CO2 $/MWh	Total $/MWh
Generic CT	12.77	0.45	0.42	0.46	7.20	21.30
CT with SCR	1.82	0.45	0.42	0.46	7.20	10.36
Steam Turbine	7.75	0.02	0.02	0.07	5.40	13.26
ST with SCR	1.14	0.02	0.02	0.07	5.40	6.65
CCGT	4.56	0.02	0.14	0.23	3.60	8.55
CCGT with SCR	0.68	0.02	0.14	0.23	3.60	4.67
Hunters Point	10.34	0.05	0.05	0.08	4.08	14.60
Morro Bay	5.38	2.84	0.07	0.35	3.33	11.97
Moss Landing	6.60	0.76	0.04	0.14	3.21	10.76
Oakland CT	10.52	7.25	0.98	1.06	16.60	36.41

Table 5 shows the same information using the updated CEC cost estimates.

Table 5: Sample Emission Costs by Plant - 1998 CEC Estimates

Internal CEC Emission Costs	NOx $/MWh	SO2 $/MWh	VOC $/MWh	PM10 $/MWh	CO2 $/MWh	Total $/MWh
Generic CT	2.52	0.18	0.05	0.09	7.20	10.04
CT with SCR	0.36	0.18	0.05	0.09	7.20	7.88
Steam Turbine	1.53	0.01	0.00	0.01	5.40	6.96
ST with SCR	0.23	0.01	0.00	0.01	5.40	5.65
CCGT	0.90	0.01	0.02	0.05	3.60	4.57
CCGT with SCR	0.14	0.01	0.02	0.05	3.60	3.81
Hunters Point	2.04	0.02	0.01	0.02	4.08	6.16
Morro Bay	1.06	1.13	0.01	0.07	3.33	5.60
Moss Landing	1.30	0.30	0.01	0.03	3.21	4.85
Oakland CT	2.08	2.87	0.12	0.21	16.60	21.89

If one compares the relative contribution of different pollutants to the various externality estimates that have been made at the state level, the tables show that NOx and CO2 tend to be the main components of the total plant emission values. The emission values for SO2 are a significant component of the totals for the Morro Bay and Oakland plants, but we expect these values to be lower in the future. The tables also show that the total emission costs, based on the ER94 valuations, are significantly above the $6/MWh used for the 1999 CBEE valuations. Most of the values estimated for generic and existing plants are around $10-14/MWh.

The total emission costs, based on the updated CEC valuations, are generally around $5-7/MWh, rather close to the $6/MWh used for the 1999 CBEE valuations. The costs drop by a factor of five for NOx emissions, yet NOx impacts still dominate compared to the VOC and PM10 values. For the generic plants (burning natural gas) the SO2 values are also small, although for the historic PG&E plants, the residual oil burns result in SO2 values for Morro Bay and Oakland on par with the NOx costs. Again, we expect these values to fall in the future.

In all of the valuations, CO2 costs are a major component of the total emissions adder values. This is rather surprising, given that CO2 is the one pollutant that is not currently regulated at the Federal or State level. Only Oregon requires CO2 offsets, based on their maximum generation emission rate, which is about 10% below that of the best available combined-cycle gas turbine. The $9/ton used in this analysis assumes that CO2 values would rise significantly above the median cost of carbon offset transactions reported to date, which is about $2.5/ton, according to the World Bank.

The NOx values, based on the internal CEC 1998 emission cost values, are based on 1994 to 1998 RECLAIM price levels. Note, however, that the recent RECLAIM prices for forward credits between 2003 and 2010 ($9,370/ton in June 2000 and $12,300/ton in August 2000) are much closer to the ER94 value. Prices for current RECLAIM credits are even higher. This illustrates one of the difficulties with basing externality values on observed market prices, i.e., that such prices can change drastically in a short period of time. Also, it can be difficult to determine if such price fluctuations represent short-term anomalies or permanent shifts in the structure of the market or the marginal costs of the emission control technologies being employed.

Assessment of Emission Reduction Costs for NOx

Summary: For at least the next few years, it can be assumed that the incremental control technology, for new and existing generators, will be selective catalytic reduction (SCR). The cost of SCR technology is estimated at $35/kW, representing an 85% reduction in emissions. Depending on a generation plant's capacity factor, heat rate and baseline emission rate, the cost of SCR emission reduction ranges between $1000-3000/ton.

NO_x emissions are controlled by modifying the combustion process or through post-combustion controls. Optimal control of combustion air can reduce NO_x emissions by 15-40%, and low-NO_x burners, which use multi-stage combustion, can provide 40-60% reductions. Post-combustion technologies include a) urea injection (which can reduce 35-75% of flue gas NO_x by changing its composition to basic nitrogen and water), and b) selective catalytic reduction (SCR), which accomplishes 80-90% NO_x removal by mixing the flue gas with ammonia in the presence of a vanadium (or other) catalyst.

Existing environmental regulations have led to the installation of low-NOx burners at all operating generating stations, so SCR is the readily applicable incremental reduction measure. New plants are required to install this technology in order to meet the Best Available Control Technology (BACT) requirements, and they must obtain offsets for any emission increase.[5]

In areas that are in serious or severe non-attainment status with regard to certain pollutant species (which is the case for almost all of California in terms of NOx), many regional air districts are now requiring Best Available Retrofit Control Technology (BARCT). This will essentially mandate SCR retrofitting of existing plants as well. Once this process is complete, the incremental emission reduction technology will have to exceed SCR performance levels. At present, it is unclear what technologies can achieve such performance, and at what cost.

However, at least for the next few years, it can be assumed that the incremental control technology, for new and existing generators, will continue to be SCR. The SCR technology's cost is estimated at $35/kW, resulting in an emissions reduction of about 85%. As shown in Table 6, the resultant SCR-based incremental generation cost varies depending on the plant capacity factor.

Table 6. Incremental cost of SCR technology as a function of capacity factor

Generation Capacity Factor	Incremental Cost ($/MWh)
0.2	3.3
0.5	1.3
0.8	0.8

The emission reduction per MWh generated also depends on the baseline emission rate, as shown in Table 7:

Table 7. Emission reductions from SCR technology in generic generating plants

Technology	Generator Heat Rate (Btu/kWh)	Baseline Emissions (lb./MWh)	Reduced Emissions (lb./MWh)	Net Reduction (lb./MWh)
Combustion Turbine	14,000	2.8	0.4	2.4
Steam Turbine	10,500	1.7	0.25	1.45
Combined-Cycle GT	7,000	1.0	0.15	0.85

[5] New plants outside California are more likely to be subject to Prevention of Significant Deterioration (PSD) rules, which require BACT under the less stringent Federal definition and may allow technologies other than SCR.

Based on the representative values given above, one can estimate sample SCR emission reduction costs relative to various types of generating plants; see Table 8:

Table 8. Emission reduction costs for SCR technology in generic generating plants[6]

Technology	Capacity Factor	Incremental Cost ($/MWh)	Net Reduction (lb./MWh)	Emission Reduction Cost ($/ton)
Combustion Turbine	0.20	3.3	2.4	2750
Combustion Turbine	0.50	1.3	2.4	1080
Steam Turbine	0.50	1.3	1.45	1790
Steam Turbine	0.80	0.8	1.45	1100
Combined-Cycle GT	0.50	1.3	0.85	3060
Combined-Cycle GT	0.80	0.8	0.85	1880

Assessment of Emission Trading Markets for NOx

Summary: The most active NOx market is the South Coast AQMD's RECLAIM program. The price of RECLAIM NOx credits was remarkably steady at around $1800/ton during the 1995-1998 timeframe. Since 1999, however, the average forward price for 2003-2010 credits has reached $9370/ton. Current credit prices are higher still, exceeding the ER94 NOx externality value by a factor of two or three. It is unclear if this price activity represents a temporary market distortion or a permanent shift in market activity.

Besides SO_2, NOx emission reduction markets are the most mature, especially in the Western U.S.[7]. The most active NOx market is the RECLAIM (Regional Clean Air Incentive Market) program of the South Coast AQMD.[8] In the RECLAIM program, forward prices for NOx credits were remarkably steady from the program's 1994

[6] A note on cost units: the analyses use different cost units to describe different physical quantities. The $/MW unit indicates the cost of retrofitting generation capacity, regardless of the amount of energy that said capacity actually generates; the amount of energy generated depends on how much a unit is dispatched and how much pollution is reduced. The $/MWh values reflect the incremental cost that is added to the generation cost due to emission reductions, regardless of how much pollution is reduced; the level of pollution reduction depends on the emission intensity of the generation before and after reduction measures are implemented. This value can be compared to the cost premium of other technical measures such as fuel switching or renewable generation sources. The $/ton notations indicate the cost of reducing emissions, including the technology cost, the quantity of generation involved, and the change in emission intensity of the generation source. This value can be compared to other emission reduction costs, including emission charges, reduction credits, and technical measures.

[7] While the Eastern states are focused on SO_2, due to the dominance on coal-fired generation and the regulatory attention focused on acid rain, NOx is at least as important in the Western states. This is due to the lesser reliance on coal in the West and the concern with ground-level ozone pollution, to which NOx emissions are a principal contributor.

[8] There is also an active market for NOx credits in the Eastern U.S. under the Ozone Transport Commission. The current prices for OTC NOx allowances are just over $600/ton, down from about $4000/ton in early 1999.

initiation through early 1999. The average price for year 2010 credits ranged from $1730/ton in 1995 to $1860 in 1998, reflecting only a 7% increase over a three-year term. The South Coast AQMD reported that the supply of credits remained adequate during this time period, and that the overall rate of compliance was very high.[9]

The RECLAIM NOx prices have increased recently, because the South Coast AQMD has been slow in issuing permits for new controls, causing some sources to buy more credits at the last minute to stay in compliance. In 1999, while current 1999 credits continued to average $1830/ton, the average forward price for 2003-2010 credits reached $4100/ton. The June 2000 prices for year 2000 credits climbed to $14,650/ton, with prices for forward credits between 2003 and 2010 at around $9370/ton (see Table 1). In August 2000, prices reached $92,000/ton for current credits and $12,300 for forward credits. As a result, trading volume has decreased, as buyers are waiting for lower prices to return.

This price behavior illustrates one of the problems with using observed market clearing prices in emission trading markets as indicators of externality values. The price levels can become highly volatile, making it difficult to identify the "true value" price, which would equate to the marginal cost to society of increasing or decreasing emissions.

Based on the 1994-1998 RECLAIM price levels, which correspond closely to mid-range estimates of the marginal emission reduction cost for gas-fired generators (see below), one could imply that an externality value of around $1800/ton for NOx would be fairly robust. Indeed, this is the value that the CEC staff selected, during 1998 internal discussions involving the CEC and CBEE, to significantly lower the range of externality values compared to the values published in the 1994 Electricity Report (ER94).

Today, however, the RECLAIM market prices are higher, exceeding the ER94 NOx externality value by a factor of two or three. Are these higher recent values simply a temporary market distortion caused by the rather thin supply of RECLAIM credits? Or, do the prices signal a permanent shift in market activity, based on the declining allocation of credits and the technological limits on emission reductions? We address this question in the final section, after first considering the state of CO_2 trading markets.

Assessment of Emission Reduction Costs and Trading Markets for CO_2

Summary: Both emission reduction costs and emission trading market prices are difficult to estimate for CO_2. There is no feasible direct emission control technology, although there are many indirect emission reduction and carbon storage options. Moreover, there is not yet a functioning market for trading CO_2 emission credits. The most advanced (albeit far from a mature market) trading effort at present is the World Bank PCF, which is looking to buy carbon for around \$5/ton-CO_2. This price is higher than the prices of carbon offset transactions reported to date; the latter have a median cost of \$2.50/ton-CO_2. CO_2 reduction costs can increase rather steeply for energy-sector measures, easily exceeding \$20/ton-CO_2.

[9] South Coast AQMD, 1999, *Annual RECLAIM Audit Report*.

Although several previous studies[10] have assigned higher externality values to CO_2 than any other pollutant, this stance is hard to quantify in terms of either emission reduction costs or emission trading markets, as neither really exist at present. The existing markets for CO_2 involve mostly sporadic individual bilateral trades between emitters and developers of reduction measures. The other potentially more developed markets are not yet in full operation. These include the Prototype Carbon Fund (PCF) of the World Bank and national trading programs in Canada, Denmark and the U.K.

In terms of quantifying CO_2 emission reduction costs, the situation is completely different from that experienced with NOx and SO_2. With the latter commodities, proven flue-gas treatment technologies exist and are in widespread use with known costs. At present, no such technology is technically, much less commercially, viable for CO_2, and it is unclear if this approach will ever be feasible. Instead, a CO_2 emission reduction strategy must rely on pursuing one, or a combination of the following approaches;

- substitution of fossil-fuel energy sources by cleaner fuels (e.g., coal-to-gas),
- renewable sources,
- energy efficiency,
- emission offsets by measures in completely different activities.[11]

Thus, the nascent "markets" for CO_2 or GHG emission reduction credits or offsets are based on the costs and performance of measures ranging from energy-efficient lighting in Poland, to renewable power generation in Costa Rica, to landfill-gas recovery in Latvia, to sustainable forestry in Mexico. Such projects are difficult to compare in terms of their emission-reduction cost and performance.

Probably the most advanced GHG-trading effort at present is the PCF, which is looking to buy carbon offsets associated with World Bank investments as well as other projects in developing countries and economies in transition (Eastern Europe and the former Soviet Union). The offering price from the PCF will probably be around $20/mtC (metric-ton of carbon-equivalent) or $5/ton-$CO_2$.

This price is significantly higher than the reported prices of most bilateral carbon offset transactions conducted to date. The World Bank analyzed CO_2 offset initiatives proposed through 1998, and reported a median cost of $10/mtC ($2.5/ton-CO_2) along with a lower

---

[10] Pace Univ. Center for Environmental Legal Studies, *Environmental Costs of Electricity*, Oceana Press, New York, 1990; Electric Power Research Institute (EPRI), *Environmental Externalities: An Overview of Theory and Practice*, EPRI CU/EN-7294, EPRI, Palo Alto, CA, 1991; National Renewable Energy Laboratory (NREL), *Issues and Methods in Incorporating Environmental Externalities into the Integrated Resource Planning Process,* NREL TP-461-6684, NREL, Golden, CO, 1994; U.S. Dept. of Energy, *Electricity Generation and Environmental Externalities: Case Studies*, DOE/EIA-0598, DOE Energy Information Agency, Washington, 1995.

[11] The most common types of offset involve increasing carbon storage in terrestrial carbon sinks such as forests, or reducing other GHG emissions such as methane.

average cost. The main reason for this variance is that most of the previous transactions lacked quality control in terms of the initiative's technical or economic performance, while the PCF has set out to buy "high-quality" carbon offsets that are expected to be more expensive. If one discounts the value of the GHG reduction in some of the reported deals, then their cost-per-ton may be similar to that proposed by the PCF.

Recommendations on Methods for Valuing Environmental Externalities

Summary: E3 recommends a separate analysis of emission credit markets and reduction costs for NOx and CO_2. The key issue regarding NOx is whether the current RECLAIM market price activity represents a temporary market distortion or a permanent shift in market activity. We conclude that the recent price activity is the result of both *short-term market instability and fundamental long-term trends, and that NOx RECLAIM credit prices will retreat from their present heights but not return to the 1994-1998 levels. Thus, valuations of $3000-12,000/ton appear more reasonable than the $1800/ton value suggested by the CEC in 1998. The key issue regarding CO_2 is to reconcile the low carbon offsets prices reported to date and the potentially high future reduction costs. We conclude that a reasonable short-term value for CO_2 reductions is about $5/ton-$CO_2$, based on the World Bank PCF activity, and that the present value of future reductions is roughly $8-13/ton-$CO_2$. Thus, we conclude that a reasonable, albeit very tentative and highly uncertain, range of values for CO_2 emissions is about $5-13/ton-$CO_2$.*

To summarize the above discussion on methodological issues, the most practical methods for valuing externalities appear to be a) an estimation of marginal emission reduction costs and b) observation of market clearing prices in emission trading markets. The relevant environmental parameters are air emissions of NOx and CO_2, although SO_2 and PM-10/PM-2.5 warrant monitoring for changes in the regulatory situation.

Ideally, the TDV team should seek a set of values that reflect a convergence of observed market behavior with emission control cost values that are relatively stable. This appeared to be the case with the South Coast AQMD NOx market, where as recently as early 1999, emission credit prices had remained stable around a mid-range value for control costs ($1800/ton). Recent market activity, however, represents a dramatic departure from this stability, requiring a more detailed analysis and review of this approach.

<u>NOx Emission Valuation</u> The next step is to estimate more stable and precise externality values. With regard to NOx emissions, E3 has examined the recent RECLAIM price increases to determine whether they represent a short-term distortion a long-term trend, or some intermediate position. Ideally, one would like to identify a sustainable long-term price value, and reconcile this value with estimates of marginal emission reduction costs, based on available or emerging technologies.

To the extent that the recent price increases appear to be a short-term distortion, one should continue to rely on the 1995-1998 prices to estimate externality values. These values correspond rather closely to our best estimates of marginal emission reduction costs, based on SCR technology.

On the other hand, if the recent prices appear to be a long-term trend, one would need to forecast the price trajectory in the market between 2000-2010. In addition, to make use of marginal emission reduction costs data, one should analyze additional reduction options to identify technical measures and costs that could drive future market prices.

The present price of NOx RECLAIM trading credits for the year 2000 is more than $90,000/ton. This price has jumped from less than $2000/ton in 1998, to somewhat more than $4000/ton in 1999, to over $14,000/ton earlier this year, and now to more than six times the backstop price of $15,000/ton.[12] The forward prices (2003-2010) have followed a similar course, reaching about $9400/ton earlier this year and now at about $12,300/ton.

The sudden price spikes for current NOx credits are clearly a temporary phenomenon, as demonstrated by the dwindling volume of trading activity in the market. However, the price increases in forward credits also indicate that the RECLAIM NOx market prices will not return to the levels of 1994-1998 any time soon, if ever. Thus, the answer to the basic question that we posed above is "both," i.e., the present prices represent both a short-term anomaly and a long-term trend.

The causes of these price increases for RECLAIM trading credits can be found on both the supply and demand sides of the market. On the supply side, the RECLAIM program is designed to require major emission sources in the region to reduce NOx emissions by about 70% between 1994 and 2003. Thus, the total supply of credits has decreased from about 40,000 tons/year in 1994 to about 16,000 tons/year in 2000, and it will level off at about 12,000 tons/year in 2003. Also, some observers indicate that the South Coast AQMD has been slow in issuing credits for new controls, causing some sources to buy more credits at the last minute to stay in compliance.

On the demand side, the rising demand for electricity in California, and the threat of supply shortages, has made it more likely that some high-cost sources in the South Coast region will be dispatched more than expected. As a result, their owners may be securing more RECLAIM credits to ensure that these plants are in compliance when needed. Also, several new generation projects, totaling almost 2000 MW, are in development in the region. The expected demand from these facilities for new reductions, in order to earn emission reduction credits to offset future emissions, is probably adding to the price pressure on RECLAIM credits.

Thus, some of the causes for the NOx RECLAIM credit price increases are indeed temporary, but other causes can be expected to remain. The latter causes include the reduced total supply of credits and the demand from new power sources in the region.

---

[12] Under South Coast AQMD Rule 2105, the breaching of this backstop price should trigger an evaluation and review of the compliance and enforcement aspects of the RECLAIM program.

According to the South Coast AQMD, it was "anticipated that the price of RECLAIM trading credits would rise as emissions allocations decreased and began to more closely mirror actual facility emissions levels. The recent price increases reflect tightening emissions caps. Large purchases of credits by electric generators – operating near full capacity this summer – also have contributed to price increases."[13]

These pressures are not temporary, even if the extreme present price levels turn out to be short-lived. The market signals created by higher RECLAIM credit prices include new incentives to reduce emissions in existing facilities, for the sake of compliance or to sell credits, and even to close facilities or move to other regions with less stringent emission constraints.

According to the South Coast AQMD, many unexploited NOx emission control options exist and could be installed at a cost of $1000-8000/ton. While such measures were unviable in 1998, and only marginal in 1999, they would now be clearly cost-effective if the present level of forward credit prices continues. The installation of such measures, in turn, would help to moderate future credit prices. The retrofit of SCR technology on peaking generation plants that run at relatively low capacity factors, such as some in the South Coast region, would cost about $3000/ton, within the range noted above.

While higher NOx RECLAIM credit prices appear to be here to stay, they are self-limiting to some degree. As the market becomes convinced that prices will stay high and has some time to respond, the installation of new reduction measures should begin to free up credits and moderate prices. In the Ozone Transport Commission NOx allowance market, current prices are only about $620/ton, but these prices were above $4000/ton, for the entire first half of 1999, before moderating during the last year. Thus, while NOx credit prices in the South Coast AQMD and California generally can be expected to exceed those in other regions, we can also expect the present price spikes to moderate.

We conclude that the present forward price for NOx credits, $12,300/ton, is an upper bound on a reasonable range of future prices, and that the cost of retrofitting SCR on peaking plants, $3000/ton, is a lower bound. This price range is centered on $7500-8000/ton, the upper end of the range of marginal control costs suggested by the South Coast AQMD. This price level is somewhat less than the NOx externality value estimated in the ER94 analysis, but it is more than four times the $1800/ton value used in the internal CEC 1998 update.

<u>CO_2 Emission Valuation</u> The valuation of CO_2 emissions is particularly uncertain in the present context, because there is no feasible direct emission control technology (although there are many indirect emission reduction and carbon storage options), and because there is not yet a mature, functioning market for trading CO_2 and GHG emission credits and offsets. On the other hand, previous studies suggest that CO_2 emissions may become the most important component of environmental externality values.

[13] South Coast AQMD, http://www.aqmd.gov/news1/RECLAIM_market.htm, August 16, 2000.

Prices in the nascent CO_2 trading market reflect more on the credibility of the emission reductions than on the basic cost of reduction measures. Most CO_2 emission offset projects proposed to date involve low-cost measures that may become scarce if the market matures, for example as a result of increasing international compliance with the Kyoto Protocol. Thus, long-term equilibrium prices could be significantly higher.

As noted above, the World Bank reported a median cost of \$10/mtC (\$2.5/ton-CO_2) for CO_2 offset initiatives proposed through 1998, and their Prototype Carbon Fund (PCF) is looking to buy "high-quality" carbon offsets for around \$5/ton-CO_2. The World Bank's PCF probably represents a reasonable balance between the low cost of existing reduction options and the higher cost of reductions that will likely prove more credible.

While there is a significant quantity of potential carbon offsets involving methane emission recovery (from landfills and agriculture) and carbon sequestration (in land-use and forestry), the bulk of future offsets, assuming the carbon emission market matures, will have to be in the energy sector, where about 80% of all GHGs are emitted. The main reduction emission-reduction strategy in the energy sector involves replacing fossil-based electricity and fuel supplies with cleaner fuels, renewable sources or energy efficiency improvements. The cost of emission reductions in energy-sector projects depends on the cost premium for providing cleaner energy services and on the carbon emission intensity of the energy source being replaced, as shown in Table 9.

Table 9. Costs of carbon emission reductions in the energy sector (\$/ton-CO_2)

Energy Cost Premium	Reduction in Carbon Emission Intensity*	
	0.5 ton-CO_2/MWh (0.13 mtC/MWh)	1.0 ton-CO_2/MWh (0.25 mtC/MWh)
	Cost of Carbon Emission Reduction	
\$10/MWh	\$20/ton-CO_2 (\$80/mtC)	\$10/ton-CO_2 (\$40/mtC)
\$20/MWh	\$40/ton-CO_2 (\$160/mtC)	\$20/ton-CO_2 (\$80/mtC)
\$30/MWh	\$60/ton-CO_2 (\$240/mtC)	\$30/ton-CO_2 (\$120/mtC)
\$40/MWh	\$80/ton-CO_2 (\$320/mtC)	\$40/ton-CO_2 (\$160/mtC)
\$50/MWh	\$100/ton-CO_2 (\$400/mtC)	\$50/ton-CO_2 (\$200/mtC)

* For energy-efficiency projects, this is the carbon intensity of the energy being saved.

For example, a wind farm replacing a rather dirty generation source (1.0 ton-CO_2/MWh), at a cost premium of \$20/MWh, would produce emission reductions (and a minimum carbon offset price) at a cost of \$20/ton-CO_2 (\$80/mtC).

Beginning with this framework, the key question is then: how much emission reduction can be realized via measures with a given reduction cost? In other words, what is the marginal cost curve (analogous to a supply curve of reductions) for GHG emission reductions on a national or (assuming international trade in carbon emission credits) global scale? A great deal of research and analysis has addressed these questions.

Unfortunately, there continues to be a great deal of disagreement among studies that focus on the costs of reducing carbon dioxide emissions from fossil fuel production and use. Technical-economic (bottom-up) models identify substantial cost-effective emission reduction potential in most countries, under the assumption that existing barriers to energy efficiency can be reduced. The total emission reduction potential in most industrialized countries over the next decades is estimated at 10 to 30 percent, at no or low cost to society, and larger if increasing costs are accepted. Similar potential has been identified in several developing countries.

Studies based on macroeconomic (top-down) models, on the other hand, generally conclude that significant macroeconomic losses would result from the imposition of carbon emission limits. The energy-policy measures that the macroeconomic models evaluate are energy-price changes through, for example, carbon taxes. As modeled in top-down analyses, such measures result in a transfer of inputs to other sectors, revenue increases to governments, and an economic efficiency loss to society. Other policy interventions (e.g., regulations and other measures aimed at overcoming barriers to energy-efficiency improvements) are assumed to be expensive and sub optimal, because they are not part of the assumed economically-efficient baseline.

Top-down models suggest that a direct (Pigouvian) tax on carbon emissions, channeled through general government spending and large enough to constrain emissions, would be an expensive strategy. Many bottom-up analysts would probably agree, recognizing that market barriers to energy-efficiency improvements would inhibit an optimal response. Both groups would likely agree that a tax, perhaps revenue neutral or channeled to investment, to slowly increase the price of energy would capture the many environmental and other externalities from energy use. The bottom-up models, however, identify additional emission reduction potential under the assumption that the barriers to energy efficiency can be reduced.[14]

Resolving this fundamental controversy is beyond the scope of this report. However, we can report some of the more robust results from both camps and try to interpret their significance in the present context. Starting with the bottom-up view, a comprehensive study of carbon emission-reduction options by five national laboratories concluded that U.S. emissions of CO_2 could be returned to the 1990 level by the year 2010 with a carbon emission tax or permit market price of \$50/mtC (\$12.5/ton-CO_2).[15] Interestingly, this study also concluded that the net cost of this scenario would be close to zero, i.e., that the

---

[14] See Swisher, J.N., 1996. "Regulatory and Mixed Policy Options for Reducing Energy Use and Carbon Emissions," *Mitigation and Adaptation Strategies for Global Change*, vol. 1, pp. 23-49.
[15] Interlaboratory Working Group, 1998. *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low-Carbon Technologies by 2010 and Beyond*, ORNL-444 and LBNL-40533, Oak Ridge National Laboratory (ORNL) and Lawrence Berkeley National Laboratory (LBNL).

savings in energy and other costs would compensate for the increased investment in energy technology.[16]

If one extrapolates from these results, using the sector-specific results of this study, one finds that the carbon emission tax or permit market price would need to be about $60-100/mtC ($15-25/ton-CO_2). These cost levels apply to reduction measures with an energy cost premium on the order of only $10-20/MWh, according to Table 9.

The measures that are cited as meeting this criterion include a range of energy-efficiency measures, predominantly in the commercial sector, in buildings, factories and vehicles. On the supply side, the dominant measures are co-firing of biomass fuel in coal-fired generating plants, as well as wind turbines in favorable sites. This windpower is assumed to be produced at a busbar cost of less than $40/MWh, thus accounting for the rather small cost premium.

Top-down studies of costs of reducing CO2 emissions in the U.S. include the well-known Energy Modeling Forum (EMF) at Stanford University. This group recently produced a systematic comparison of 13 modeling analyses of GHG emission reduction costs.[17] The modelers were asked to analyze a standardized set of emission reduction scenarios over the period 1990-2050, using common assumptions for selected parameters, including GDP and GDP growth rate, population and growth rate, the fossil fuel resource base, and the cost and availability of long-term supply options. The modelers also used carbon taxes, based on the carbon content of fossil fuels, to achieve emission reductions.

The model results estimate that a tax of about $20/mtC to $150/mtC ($5-$37.5/ton-$CO_2$) is required to hold emissions at 1990 levels in 2010.[18] Estimates of carbon taxes required to reduce emissions 7% below 1990 levels by 2010 (i.e., Kyoto Protocol compliance) range from $50/mtC to $275/mtC ($12.5-$69/ton-$CO_2$). In general, models that assumed lower price elasticities and lower rate of capital stock adjustments to higher electricity prices, neither of which parameters were controlled in this study, produced higher estimates of carbon tax requirements.

Several of the models explored the effects of international carbon emission trading on emission reduction costs. As expected, unrestricted trade increases the range of reduction measures and reduces the costs of reductions. In these studies, the carbon tax for Kyoto compliance fell from $168-$275/mtC ($42-$69/ton-CO_2) with no trade to $21-31/mtC

[16] The main reason why the net cost could be zero despite the need for a carbon tax to achieve the reduction measures is the assumption that the benefits and costs to the nation are discounted at 7% (real); the private actors (households and commercial/industrial owners of buildings, factories and vehicles) that make investment decisions implicitly apply much higher discount rates to such investments, making energy-efficiency investments less attractive without the incentive of the carbon emission tax or permit cost.

[17] CETA (Peck and Teisberg), CRTM (Rutherford), DGEM (Jorgensen and Wilcoxen), ERM(Edmonds and Reilly), Fossil2 (Belanger and Naill), Gemini (Cohan and Scherga), Global2100 (Manne and Richels), Global-Macro economy (Pepper), Goulder, GREEN (Martins and Burniaux), IEA (Vouyoukas and Kouvaritakis), MARKAL (Morris), MWC (Mintzer), and T-GAS (Kaufmann).

[18] See the special Kyoto issue of the *Energy Journal*, May 1999, summarized in J. Weyant and J. Hill, pp. vii-xliii.

(\$5-\$8/ton-CO_2) with unlimited trade. The latter values correspond to the minimum price for carbon emission permits on the global market. Any transaction costs or restrictions on trading would reduce the volume of trade and increase costs.

Comparing the above sources of emission reduction cost estimates, we can attempt to define a range of trajectories for marginal reduction costs and CO_2 emission offset prices, starting with the following summary observations:

- Macroeconomic studies of Kyoto-compliance scenarios report marginal reduction cost levels and market-clearing prices for domestic emission-trading markets on the order of \$40/ton-CO_2, but some studies' results are below \$15/ton-CO_2, and several studies indicate that values less than \$10/ton-CO_2 are possible with unlimited global carbon trading.
- Bottom-up studies suggest that, even if the net cost of emission reductions is low or negative, based on a private energy cost premium of \$10-20/MWh for energy-efficiency and renewable energy, a carbon emission tax or permit price on the order of \$15-25/ ton-CO_2 would be necessary to reach Kyoto compliance.
- Generic project cost data for representative energy (supply and demand-side), land-use and methane emission reduction measures indicate that a significant quantity of potential carbon offsets involving methane emission recovery (from landfills and agriculture) and carbon sequestration (in land-use and forestry) would cost only about \$1-3/ton-CO_2, but that even low-cost (\$10-20/MWh) energy-sector measures would cost on the order of \$20/ton-CO_2.
- Reported costs of CO_2 emission offset projects identified to date vary widely, with a median cost of \$10/mtC (\$2.5/ton-CO_2) along with a lower average cost, and we estimate the present cost of high-quality CO_2 offsets to probably be in the range of \$2-5/ton-CO_2.
- The initial activities of the World Bank PCF suggest a carbon offset price of \$20/mtC (\$5/ton-CO_2).

Based on the above observations, we can try to project marginal emission reduction costs and market-clearing prices for carbon emission credits in the 2005-2010 timeframe. We conclude that a reasonable short-term value for CO_2 emission reductions is about \$5/ton-CO_2, based on the World Bank PCF activity, and that U.S. and international efforts to comply with the Kyoto Protocol, even if incomplete and not fully successful, would drive the price of carbon emission credits toward a range of \$15-25/ton-CO_2 by 2010. If one discounts these values back to 2000, at a 7% real discount rate, the present values are about \$8-13/ton-CO_2. Thus, we conclude that a reasonable, albeit very tentative and highly uncertain, range of values for CO_2 emissions is about \$5-13/ton-CO_2.

Conclusion

E3 concludes that a realistic valuation of NOx emissions is on the order of \$3000-12,300/ton, centered on \$7500-8000/ton, which is also consistent with the upper end of the range of marginal control costs we have identified. This range is much closer to the 1994 CEC emission valuations, from which the commission now distances itself, than the

1998 values. We conclude that a reasonable, albeit very tentative and highly uncertain, range of values for CO_2 emissions is about \$5-13/ton-CO_2. Thus, the \$9/ton-CO_2 value used in both the 1994 and 1998 CEC valuations appears to be reasonable. In summary, E3 concludes that a realistic valuation of environmental externalities should be closer to the CEC ER94 valuations, but perhaps at the lower end of this range. For common electric generation plants in California, this level of externality valuation corresponds to a total emission cost, or energy adder, of about \$10/MWh. This is a rough estimate!

In 1994, the CEC estimated a set of externality values for several criteria and CO_2. The Commission has since backed away from these estimates and, at least internally, indicated since 1998 that other lower values may be more appropriate. While the 1994 values were at least partly based on external studies of pollution damage costs, the CEC has since indicated that their preferred approach to externality valuation should be based on the observation of active emission-trading markets. For example, the 1998 recommendation for a NOx emission valuation corresponds closely to the 1994-1998 NOx emission credit price in the South Coast AQMD RECLAIM market.

During that time, the RECLAIM market prices were quite stable. Recently, however, RECLAIM prices have skyrocketed, casting a shadow of greater uncertainty on externality valuations based on these prices. We believe that the recent price activity is the result of *both* short-term market instability and fundamental long-term trends. Thus, we conclude that NOx emission credit prices in California will retreat from their present heights, but that they are not likely to return to the levels observed during the 1994-1998 timeframe.

Rather, we believe that a realistic valuation of NOx emissions is on the order of \$3000-12,300/ton, centered on \$7500-8000/ton, which is also consistent with the upper end of the range of marginal control costs we have identified. This range is much closer to the 1994 CEC emission valuations, from which the commission now distances itself, than the 1998 values. Still, the 1994 values would be at the upper end of our suggested range.

Regarding CO_2, the uncertainty is even greater. One could justify a valuation of zero, based on the observation that GHG emissions are not presently regulated in the U.S. On the other hand, one could apply a valuation of more than \$50/ton-CO_2, based on projected marginal costs of complying with the Kyoto Protocol during the 2010 timeframe. We conclude that a reasonable, albeit very tentative and highly uncertain, range of values for CO_2 emissions is about \$5-13/ton-CO_2. Thus, the \$9/ton-CO_2 value used in *both* the 1994 and 1998 CEC valuations appears to be reasonable.

Other emission valuations can vary over similar ranges. However, it appears unlikely that even the highest reported values would produce a significant contribution to an overall energy cost adder, as shown in Tables 4 and 5. This conclusion applies to natural gas-fired generation in California, but one might need to reconsider Sox emissions to estimate externality values for coal-fired generation, especially in Eastern states.

These tables indicate that the total emission costs, based on the CEC ER94 valuations, would be around $10-14/MWh, and that the total emission costs, based on the updated CEC valuations, would be around $5-7/MWh, rather close to the $6/MWh used for the 1999 CBEE valuations. From our observations and analysis, described above, E3 concludes that a realistic valuation of environmental externalities for common electric generation plants in California should be closer to the CEC ER94 valuations, but perhaps at the lower end of this range, or very roughly, about $10/MWh.

Appendix 1

Methodological Options for Valuation of Environmental Externalities

There are several basic approaches to valuing externalities:

- Qualitative approaches
- Estimation of marginal emission abatement costs
- Observation of market clearing prices in emission trading markets
- Estimation of marginal damage costs
- Willingness-to-pay analysis

Qualitative approaches include various uses of ranking and expert judgment, and these are not considered here because valuation of externalities is quantitative by definition.

Estimation of marginal emission abatement costs relies on the cost of incremental emission reductions, beyond the current regulated level, as an indication of the value of incremental emissions. The theory behind this approach is the current level of legislated/regulated emission compliance is based on a societal consensus, making this level the efficient degree of emission reduction. Therefore, at this efficient level, the marginal cost of abatement should (theoretically) be equal to marginal benefit of emission reductions. In reality, of course, the regulated emission levels are known to be political decisions that may have little to do with the economically optimum level of reductions or reduction costs. Nevertheless, once emission controls are in place, this is an easily observable criterion.

Observation of market clearing prices in emission trading markets is another easily observable criterion. This approach is also based on the theory that the current level of emission compliance represents the efficient degree of emission reduction. It is similar to the previous approach, as emission-trading market prices are assumed to be based on the participants' marginal cost of abatement. However, this approach allows for possible increases or decreases in cost, depending on the degree to which current reduction limits constrain the technical options of the market participants. As observed in comparing the SCAQMD credit prices to the CEC externality estimates (see Tables 1 and 2), the sensitivity of price levels to credit supply and demand, for whatever reason, can make these values relatively unstable and difficult to extrapolate from.

Estimation of marginal damage costs is a more theoretically correct use of economics. Assuming that one can accurately estimate both the environmental damage cost function (i.e., the demand for emission reductions) and the abatement cost function (i.e., the supply of emission reductions), the optimal solution would be the point where marginal damage cost equals marginal abatement cost. This also assumes that damages from all sources are considered, and that reductions from all sources are considered and can be implemented. Despite its theoretical elegance, this approach is very difficult to apply in practice. The analysis of damage cost functions is especially difficult and imprecise; many existing studies vary in their results by more than an order of magnitude on several basic parameters. In addition, the basic assumptions that all or most sources are included in the damage and abatement functions are generally not valid in reality.

The environmental damage represented by the damage function conversely can represent the potential benefit to be provided by reducing emissions, via energy-efficiency projects and programs. These benefits, or avoided damages, of reduced air emission from electricity generation can take several forms:

- Reduced mortality from respiratory disease
- Reduced health care costs from respiratory disease and other ailments
- Reduced asthma, eye irritation and other chronic health problems
- Additional attendance and production from workers due to reduced sickness
- Reduced material damage, such as from acid deposition and ozone
- Additional visibility, especially in pristine areas, from reduced particulates
- Reduced agricultural losses, such as from acid deposition and ozone
- Improved ecological health, including lake and forest health and productivity
- Reduced risk of global climate change, and health, economic and ecological losses

Additional environmental impacts, besides those of air emissions, cause health and economic damage as well. Compared to air emission impacts, these impacts tend to be more related to facility siting (of generation and transmission equipment) than the incremental production of electricity (i.e., fuel use at the marginal plant). These impacts and the related damages include:

- Destruction of land resources by surface mining of coal; cost of reclamation
- Land flooded to provide hydroelectric storage reservoirs, include pristine river valleys
- Loss of residential or commercial uses, and reduced value, of surrounding land
- Waste disposal of ash from coal combustion, some of which is radioactive or toxic
- Sludge waste from air pollution control equipment
- Radiation releases from routine operation and accidents at nuclear generation plants
- Long-term disposal of radioactive wastes from nuclear power plants
- Visual impacts from generation and transmission facilities
- Magnetic fields created by high-voltage transmission lines
- Water consumption for condenser cooling at thermal generation plants
- Thermal pollution, which lowers dissolved oxygen and endangers aquatic life

A willingness-to-pay analysis is a variation on the previous approach. Rather than try to assess directly the value of damages from pollution, this approach uses contingent valuation and other techniques to reveal indirectly the value that society would pay to avoid the incremental unit of emissions. While this approach has been used with some success to value land-use resources such as recreational facilities, it becomes highly subjective and inaccurate when applied to air emissions, which have more pervasive health impacts and other costs to society.

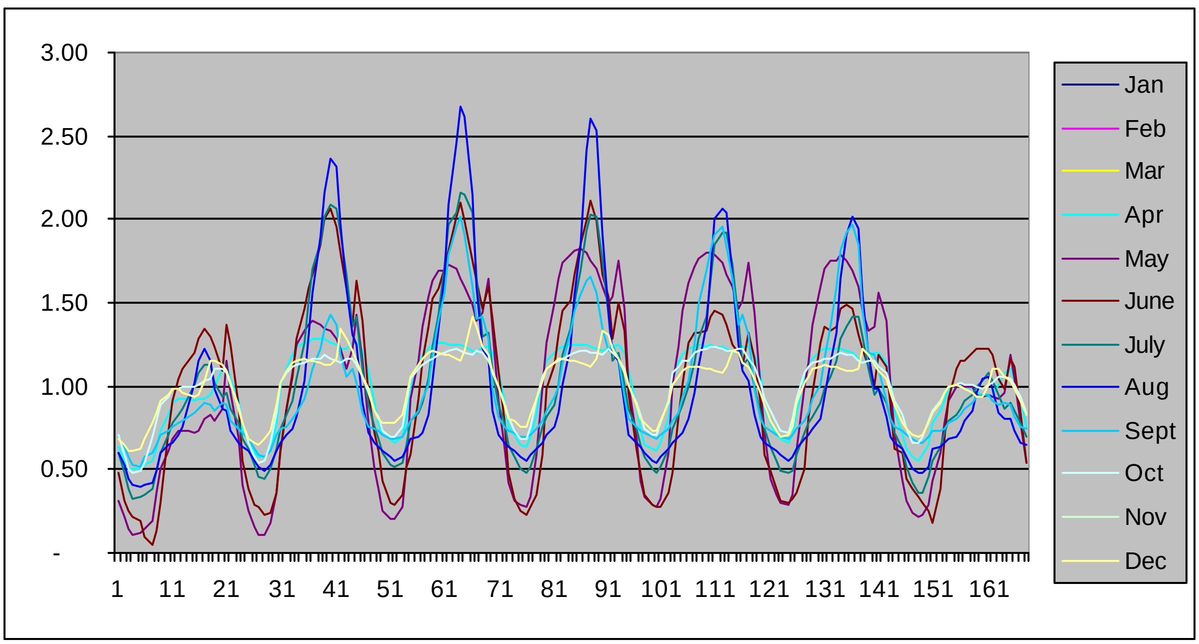
Projection of Price Shapes

The CEC currently updates its market price forecasts on at least an annual basis, and has recommended to the State Legislature that it continue to do so in the future.[1] As part of the forecast development, the CEC's models calculate hourly market prices for typical weeks for each of the twelve months. The hourly prices have been derived by mapping the typical week to the 28 to 31 days in each month, and scaling all of the monthly prices up to match the forecasted market price for that month. The monthly market price is developed by applying fixed monthly price ratios to the annual average forecast market price. The monthly scale factors are shown below.

	Monthly Scaler
Jan	0.979
Feb	0.895
Mar	0.777
Apr	0.67
May	0.618
Jun	0.625
Jul	0.961
Aug	1.569
Sep	1.642
Oct	1.094
Nov	1.068
Dec	1.092

Price[m,h] = Annual Avg Forecast * Monthly Scaler[m] * Typical Shape[m,h]

Figure 1: Monthly typical week market price profiles normalized to average 1.0.



[1] Keese, W.J., et al, (2000) *Forecasting & Data Collection Responsibilities*, SB110 Report to the Legislature, California Energy Commission (CA: Sacramento)

The typical week shapes for the hourly market price forecast can be found in Monthyhrly2005s2.xls [Original CEC Hourly Forecast].

Load Profile Source

The 1999 Statistical Load Profiles we used can be found below with links to their original source. These shapes were subsequently normalized and adjusted in timing to match the weekends and holidays for 1991 to comply with the ACM manual.

PG&E
http://www.pge.com/006_news/006f1c4b_1999static_load_prof.shtml

Shape Name: E1 Residential
(covers E-1, E-8, E-13)

Shape Name: A10 Non-Residential

SCE
http://www.sce.com/sc3/005_regul_info/005h_sce_profiles/005h4_99_staticloadpro.htm

Shape Name: Dom-S/M
(covers D, D-CARE, DE, DS, TOU-D-1, TOU-D-2,TOU-EV-1, TOU-EV-2. rate schedules)

Shape Name: GS 2
(covers GS-2, GS-2-RTP, RTP-2-GS, RTP-3-GS,TOU-EV-4. rate schedules)

SDG&E

http://www.sdge.com/cust_choice/pxinfo/static.html

Single spreadsheet with 7 classes not directly linked to rates.

Shape Name: Residential

Shape Name: Med C/I <500 kW

Climate Zone Mapping

The shapes for each respective utility were then mapped to climate zone with the following mappings. For those climate zones with more than one utility, the utility shown in bold was used. This was selected by using the utility that serves the most customers in the zone.

Climate Zone	**Utility**
1	PG&E
2	PG&E
3	PG&E
4	PG&E
5	**PG&E** (SCE)
6	SCE
7	SDG&E
8	SCE
9	SCE
10	**SCE** (SDG&E)
11	PG&E
12	PG&E
13	PG&E
14	**SCE** (SDG&E)
15	**SCE** (SDG&E)
16	**PG&E** (SCE)

Costs to Build and Operate a New Plant

A revenue stream sufficient to attract a new commercial power plant for the California market would cover its fixed costs and costs of operation, including fuel costs. Covering the variable costs of operation need not be of much concern, because the plant does not have to operate if it cannot recover these costs. Therefore, an investment decision will concentrate on recovering fixed costs. These include the ongoing operation and maintenance (O&M) costs that are unavoidable whether the plant operates or not, plus the money that is required to reimburse the lenders and investors who financed the plant. The lenders and investors expect returns comparable to the returns available from other investments of similar risk.

The cost of building a new power plant depends on what technology is employed, which company supplies the equipment, the specific site, environmental mitigation requirements, and other factors. Many kinds of generating plants could be built for the California market, but this chapter focuses on combined cycle and simple cycle plants that are fueled by natural gas. The majority of new proposed merchant power plants are fueled by natural gas. In general, power plants employing other technologies will be smaller, less efficient, and tend to have higher revenue requirements per kilowatt than do gas-fired plants.

Cost estimates for combined cycle plants known to be in some stage of planning or construction tend to group in the neighborhood of $600/kW for a 500 MW plant. **Table 4-1** shows some of the cost estimates the Energy Commission's Siting Division has received from project developers.[1] The estimates may not be comparable, because they do not rely on a standard methodology or common set of features. All the plants listed in **Table 4-1** are large in comparison to most existing gas-fired generation plants. Smaller plants will probably be more expensive on a $/kW basis, due to economies of scale.

No simple cycle gas turbines are reported under construction to provide a cost estimate. Estimates in the *1998-1999 Gas Turbine World Handbook* indicate that the cost of a simple cycle plant, on a $/kW basis, is about 60 percent of what a combined cycle costs. Therefore, we will characterize the cost of a 500 MW simple cycle plant as $360/kW (60 percent of $600/kW). This comports well with an estimate of $356/kW for a 936 MW simple cycle project in Georgia[2].

1. See http://www.energy.ca.gov/sitingcases/index.html for a complete list.
2. See http://www.standardandpoors.com/ratings/infrastructurefinance/index.htm.

Table 4-1
Cost Estimates for Power Plant Projects
(All are gas-fired combined cycle)

		Cost		County
	MW	($ Million)	$/kW	
Blythe	520	250	481	Riverside
Elk Hills	500	300	600	Kern
La Paloma	1048	730	697	Kern
Long Beach	500	300	600	Los Angeles
Los Medanos	500	300	600	Contra Costa
Midway-Sunset	500	250	500	Kern
Mountainview	1056	550	521	San Bernardino
Otay Mesa	510	350	686	San Diego
Nueva Azalea	550	450	818	Los Angeles
Sutter	500	275	550	Sutter
California Three Mountain	500	300	600	Shasta

In addition to the costs of the facility, developers must also recover the cost of money. Plants are usually financed with a combination of debt and equity (stock). The proportions of each vary from project to project, with projects thought to be riskier usually requiring more equity. Of course, equity investors cannot require a rate of return, but they will probably not invest unless prospects for returns exceed a certain threshold.

No power plant developer knows what the exact arrangements for financing a project will be until completion of negotiations with lenders, lawyers, investors, and financial consultants, and no standard formulas exist. Staff reviewed current literature on power plant financing to find the most authoritative, documented sources and relied mainly on a Moody's Investors Service article, and the Northwest Power Planning Council's March 2000 report on supply adequacy. [3,4] The Moody's article suggested that power plant projects be analyzed using debt/equity ratios of 70/30 or 60/40, 8.5 percent interest, 14 percent return on equity, and 25-year amortization. The Northwest Power Planning Council report uses 70/30, 8.7 percent interest, 17.3 percent return on equity, and 15-year amortization. The Moody's article appeared to assume that a new power plant would receive capacity payments as well as energy payments, which would tend to make the project less risky. Capacity payments are not offered in California.

---

3. Moody's Investors Service special comment by Andy Jacobyansky and Susan Abbott, September 1999.
4. See http://www.nwppc.org.

The range of financial assumptions and resulting revenue requirements to cover the capital costs of new simple cycle and combined cycle power plants are shown on **Table 4-2**.

Table 4-2
Financial Assumptions and Resulting Revenue Requirements for Construction of New Gas-Fired Power Plants in California

	Simple Cycle		Combined Cycle	
	Low	*High*	*Low*	*High*
Construction Cost ($/kW)	340	380	550	650
Debt/Equity	60/40	60/40	60/40	60/40
Amortization Period (yrs.)	30	25	30	25
Interest Rate on Debt	8.5%	8.5%	8.5%	8.5%
After-tax Return on Equity	17.1%	20.5%	12.0%	17.1%
Tax Rate	40%	40%	40%	40%
Non-Capital Fixed Cost ($/kW-yr)	5	5	10	10
Revenue Requirement ($/kW-yr)	55	70	74	107

Sources of Revenue

Generators in the California market receive revenue to cover their costs by selling electrical energy and ancillary services. "Electrical energy" means electricity, measured in kilowatt-hours (kWh) or megawatt-hours (mWh). "Ancillary services" means the various services that a generator can provide to improve the reliability and functionality of the overall power grid.

Energy Revenue

Generators can sell their electrical energy to any buyer for any price under the terms of private contracts, and the terms of such a contract need not be publicly disclosed. However, since April 1, 1998, most of the electrical energy in California has been bought and sold through the California Power Exchange (PX), and PX prices are public. It is logical that energy prices in private contracts bear some similarity to actual or expected PX prices. If PX prices were lower, the purchaser evaluating a private contract would likely avoid the contract and buy through the PX. If PX prices were higher, the seller evaluating a private contract would likely avoid the contract and sell through the PX. Therefore, PX prices should provide a fair measure of generators' profitability, even though some generators may receive most or all of their revenues under the terms of private contracts.

The energy prices necessary to cover revenue requirements can be computed by estimating the plant's operating costs and how many hours it is running. A generating unit's operating costs consist of fuel costs plus non-fuel variable operation and maintenance (O&M) costs. This analysis uses a natural gas price of $2.90 per million Btu, which is about equal to the average price of natural gas delivered for utility electric generation in California during April 1, 1999, through March 31, 2000.[5] As heat rates, we use 6,800 Btu/kWh for a combined cycle unit and 9,100 Btu/kWh for a simple cycle unit. These heat rates are consistent with published data about the efficiency of generator sets currently available from major manufacturers, such as General Electric or Siemens-Westinghouse. Based on the experience of units already in operation, we estimated variable O&M costs of $2.00 and $3.00 per MWh for combined cycle and simple cycle generating units, respectively.

To maximize revenue, the operators of a merchant plant should try to operate and take the market price during all the hours when the market price is at least as great as the operating cost

The revenue requirements from **Table4-2** and operating costs were placed in this equation to solve for "Average Price." This calculation produces the average price a plant would need to receive in order to recover its revenue requirements in a given number of hours, stated as fraction of an 8,760-hour year. A range of results are shown on **Table 4-3**, which assumes a 2 percent forced outage rate. If a plant runs only 10% of the year, a simple cycle is cheaper than a combined cycle , but they are both expensive.

Combined cycle generating units can operate profitably under lower prices than can simple cycle units, because they are more efficient. However, combined cycle units are also more expensive to buy or construct, so they require more hours of profitable operation to clear revenue requirements.

Table 4-3
Average Prices Needed to Recover Investment
In "Low" and "High" Revenue Requirement Cases
$/MWh

Fraction Of Year	**Simple Cycle**		**Combined Cycle**	
	Low	***High***	***Low***	***High***
10%	94.06	111.53	108.36	146.80
20%	62.02	70.76	65.26	84.48
30%	51.35	57.17	50.90	63.71
40%	46.01	50.37	43.71	53.32
50%	42.80	46.30	39.40	47.09
60%	40.67	43.58	36.53	42.94
70%	39.14	41.64	34.48	39.97
80%	38.00	40.18	32.94	37.74
90%	37.11	39.05	31.74	36.01
100%	36.40	38.14	30.78	34.63

5. A historical gas price was used rather than a forecast price so as to allow a meaningful comparison of historical energy prices to the prices that a hypothetical power plant needs to clear revenue requirements.

PCAF and Temperature Correlations

In order to allocate the transmission and distribution (T&D) marginal cost to hours of the year, an approach was adopted from the utility T&D capacity planning process. In utility practice, this approach develops allocation factors for T&D costs based on observed loads in an area. For the building standards process, temperature in a climate zone is used as a proxy for loads. This is justified by the fact that temperature is the main driver of peak loads in an area. This document shows the relationship between the 'temperature proxy' method and the actual method that PG&E uses to allocate capacity costs.

E3 obtained hourly estimated load data for calendar year 1999 for all of PG&E's 200 plus distribution planning areas. E3 selected a sample of 33 areas for analysis. The samples were drawn to represent each of the 16 PG&E divisions, each of the 4 PG&E-defined climate zones, and a meaningful mix of areas.

The characteristics of the sample areas are shown below.

DPA Number	DPA Name	DPADIV	Weather Station	Max	Average	Load Factor	Stdev	Thresh %	Smr Max	Peak Season	%Res (by customer count)	Climate Zone
6	ARCATA	NORTH COAST	Arcada	36,772	21,895	60%	4,938	13%	31,205	Winter	89%	Coastal
20	C-D-L	EAST BAY	Oakland	231,188	148,516	64%	33,581	15%	231,188	Smr	86%	Hill
25	CENTRAL FRESNO	FRESNO	Fresno	477,887	185,452	39%	62,031	13%	477,887	Smr	88%	Desert
31	CHICO 12 KV	NORTH VALLEY	Red Bluff	207,548	76,652	37%	23,117	11%	207,548	Smr	84%	Valley
35	CLARKSVILLE/SHINGLE SPR.	SIERRA	Sacramento	99,218	39,443	40%	11,050	11%	99,218	Smr	89%	Valley
44	CONCORD	DIABLO	Concord	372,222	166,477	45%	42,487	11%	372,222	Smr	92%	Hill
51	DELTA	DIABLO	Stockton	339,142	111,810	33%	33,981	10%	339,142	Smr	92%	Valley
58	EUREKA	NORTH COAST	Arcada	45,409	29,124	64%	6,425	14%	39,508	Winter	87%	Coastal
71	HAYWARD 12 KV	MISSION	Hayward	380,130	211,937	56%	47,169	12%	380,130	Smr	91%	Hill
80	K-X	EAST BAY	Oakland	87,081	48,421	56%	11,662	13%	71,529	Winter	95%	Hill
88	LERDO	KERN	Bakersfield	95,019	46,410	49%	15,229	16%	95,019	Smr	66%	Desert
91	LIVERMORE 21 KV	MISSION	Livermore	92,660	40,273	43%	9,939	11%	92,660	Smr	89%	Hill
113	MERCED 12 & 21 KV	YOSEMITE	Merced	131,723	57,234	43%	17,124	13%	131,723	Smr	87%	Desert
116	MILPITAS	SAN JOSE	San Jose	279,400	161,914	58%	28,903	10%	279,400	Smr	92%	Hill
117	MONTEREY 21 KV	CENTRAL COAST	Monterey	46,077	28,764	62%	6,414	14%	38,434	Winter	87%	Coastal
121	MOUNTAIN VIEW	DE ANZA	Moffett	172,172	94,971	55%	20,408	12%	172,172	Smr	91%	Hill
124	NAPA	NORTH BAY	Napa	130,655	63,969	49%	15,279	12%	130,655	Smr	86%	Hill
126	NETWORKS	SAN FRANCISCO	San Francisco	568,260	352,634	62%	88,851	16%	568,260	Smr	92%	Coastal
133	NORTH PEN WEST 12 KV	PENINSULA	Moffett Field	174,477	103,961	60%	24,453	14%	150,065	Winter	92%	Coastal
136	NORTH STOCKTON 12 KV	STOCKTON	Stockton	249,527	86,112	35%	26,483	11%	249,527	Smr	91%	Valley
144	OROVILLE 12 KV	NORTH VALLEY	Oroville	106,306	41,686	39%	11,718	11%	106,306	Smr	83%	Valley
160	RADIAL	SAN FRANCISCO	San Francisco	224,315	147,698	66%	33,472	15%	210,703	Winter	Missing	Coastal
162	REDDING 12 KV	NORTH VALLEY	Redding	102,147	41,636	41%	11,596	11%	102,147	Smr	89%	Desert
173	SAN JOSE (SOUTH)	SAN JOSE	San Jose	437,756	199,357	46%	49,473	11%	437,756	Smr	96%	Hill
175	SAN LUIS OBISPO	LOS PADRES	San Luis Obispo	60,740	41,639	69%	8,739	14%	60,740	Smr	82%	Coastal
179	SANTA MARIA	LOS PADRES	Santa Maria	98,707	67,475	68%	14,149	14%	97,050	Winter	88%	Coastal
182	SEASIDE MARINA 12 KV	CENTRAL COAST	Monterey	61,224	41,109	67%	8,624	14%	57,262	Winter	93%	Coastal
192	SOUTH PEN 12 KV	PENINSULA	Moffett Field	262,815	133,876	51%	32,814	12%	262,815	Smr	Missing	Coastal
195	SOUTH STOCKTON 12 KV	STOCKTON	Stockton	212,019	100,375	47%	26,222	12%	212,019	Smr	77%	Coastal
198	STOREY	YOSEMITE	Madera	126,397	56,970	45%	17,647	14%	126,397	Smr	38%	Desert
205	URBAN BAKERSFIELD	KERN	Bakersfield	706,576	284,348	40%	91,699	13%	706,576	Smr	84%	Hill
206	VACAVILLE	SACRAMENTO	Vacaville	168,174	62,907	37%	17,531	10%	168,174	Smr	89%	Desert
216	WEST SACRAMENTO	SACRAMENTO	Sacramento	78,530	39,459	50%	8,836	11%	78,530	Smr	0%	Valley

Threshold % indicates how much of the load duration curve is defined to be in the "peak period." For ratemaking purposes PG&E has used 20%. For resource planning studies, however, one standard deviation has been used by PG&E and other utilities. The one standard deviation definition is used for the TDV study.
%Res is the percentage of the accounts in the area that are residential.
Maximum and Average are the demands in the area in kW.

Weather data was obtained from the National Climatic Data Center. The hourly temperature data is unedited, so that some data was missing. Most notably, all of November, and much of the data for Arcada was not available. Oakland was also not available. The missing November data had little impact on the analysis, but the Arcada data resulted in the elimination of Arcata and Eureka from the sample, and San Francisco airport temperature data was used as a proxy for Oakland.

PCAF Calculations

The Peak Capacity Allocation Factors were calculated from the simulated hourly shapes provided by PG&E's rate department. The simulated shapes are from PG&E's AREALOAD model which PG&E has employed and defended in the regulatory arena in various forms since 1992. Actual measured data for 1999 is available for some substations and circuits through PG&E's SCADA system. E3 chose to use the simulated data set to assure full representation of the loads within a DPA (often SCADA does not cover an entire area) and to assure representation of all the DPAs (SCADA is not fully deployed across PG&E's entire service territory.)

Weather Data

The NCDC lists 59 weather stations with hourly data for California. 30 of the stations are within PG&E's service territory, and E3 employed twenty weather stations in this study. E3 believes these weather stations provide a reasonable representation of weather conditions across the entire state, with the exception of the high mountains and the low desert.

PCAF Correlations

Examination of the 31 sample areas revealed that for summer peaking areas, the peak period occurred during hours with temperatures within 15 degrees of the annual maximum. For example in a moderate area like Mountain View, the peak temperature in 1999 was 93 degrees. In an area like this, temperatures in the high eighties would be of concern to the planners. Conversely, in Concord where the temperature topped out at 106 degrees, the main concern to planners would be usage when the temperature rises into the mid to high nineties.

Having determined the duration of the peak period, the next task was to develop a functional form based on temperature that would reasonably match the actual PCAFs. For simplicity, E3 settled on a simple functional form that increased linearly with temperature.

Avoided Transmission and Distribution Costs

The interim administrators provided the TSC with recent forecasts of avoided T&D costs by service territory. The TSC weighted these estimates by 1996 sales for each utility to develop a statewide average. The TSC converted the values from $/kW to $/kWh by assuming a 0.6 load factor.

96sales	73.318		15.981		73.784				
salewght	0.45		0.10		0.45				load factor
									0.6
	PG&E $/kW		SDG&E $/kW		SCE $/kW		Wght Ave $/kW		$/MWh
1999	44.7		12.7		7.4		24.7		4.69
2000	46.6	0.043	13.1	0.033	7.6	0.035	25.7	0.041	4.88
2001	48.6	0.043	13.6	0.032	7.9	0.035	26.7	0.041	5.09
2002	50.7	0.043	14.0	0.032	8.1	0.035	27.8	0.041	5.29
2003	52.8	0.043	14.5	0.034	8.4	0.035	29.0	0.041	5.51
2004	55.1	0.043	15.0	0.035	8.7	0.035	30.2	0.041	5.74
2005	57.4	0.043	15.5	0.035	9.0	0.035	31.4	0.041	5.98
2006	59.9	0.043	16.0	0.035	9.4	0.035	32.7	0.041	6.23
2007	62.5	0.043	16.6	0.035	9.7	0.035	34.1	0.041	6.48
2008	65.1	0.043	17.2	0.035	10.0	0.035	35.5	0.041	6.75
2009	67.9	0.043	17.8	0.034	10.4	0.035	37.0	0.041	7.03
2010	70.8	0.043	18.4	0.034	10.7	0.035	38.5	0.041	7.32
2011	73.8	0.043	19.0	0.035	11.1	0.035	40.1	0.041	7.63
2012	77.0	0.043	19.7	0.035	11.5	0.035	41.7	0.041	7.94
2013	80.3	0.043	20.3	0.033	11.9	0.035	43.5	0.041	8.27
2014	83.7	0.043	21.0	0.033	12.3	0.035	45.3	0.041	8.61
2015	87.3	0.043	21.7	0.033	12.7	0.035	47.1	0.041	8.97
2016	91.0	0.043	22.4	0.033	13.2	0.035	49.1	0.041	9.34
2017	94.9	0.043	23.2	0.033	13.7	0.035	51.1	0.041	9.73
2018	99.0	0.043	24.0	0.034	14.1	0.035	53.2	0.041	10.13

Sources: Mike Wan (10/1/98) PG&E System Average Capacity Values ($/kW-yr) for DSM Evaluation
Athena Besa (10/2/98) Avoided T&D Costs
Don Arambula (9/9/98) 1999 Avoided Costs for Retrofit Programs T&D Value $/kW-yr

APPENDIX K

GDP IMPLICIT PRICE DEFLATOR SERIES
(1998 = 100)

Year	Index	Annual Growth Rate	Year	Index	Annual Growth Rate
1970	27.01		1995	95.26	2.3%
1971	28.41	5.2%	1996	97.05	1.9%
1972	29.61	4.2%	1997	98.85	1.9%
1973	31.28	5.6%	1998	100.00	1.2%
1974	34.08	9.0%	1999	101.81	1.8%
1975	37.29	9.4%	2000	103.85	2.0%
1976	39.47	5.8%	2001	106.23	2.3%
1977	42.02	6.5%	2002	108.64	2.3%
1978	45.02	7.3%	2003	111.01	2.2%
1979	49.93	8.5%	2004	113.39	2.1%
1980	53.45	9.2%	2005	115.87	2.2%
1981	58.48	9.4%	2006	118.65	2.4%
1982	62.17	6.3%	2007	121.62	2.5%
1983	64.82	4.3%	2008	124.82	2.6%
1984	67.27	3.8%	2009	128.30	2.8%
1985	69.58	3.4%	2010	132.09	3.0%
1986	71.40	2.6%	2011	136.23	3.1%
1987	73.59	3.1%	2012	140.61	3.2%
1988	76.28	3.7%	2013	145.29	3.3%
1989	79.49	4.2%	2014	150.22	3.4%
1990	82.93	4.3%	2015	155.62	3.6%
1991	86.23	4.0%	2016	161.50	3.8%
1992	88.60	2.8%	2017	167.82	3.9%
1993	90.94	2.6%	2018	174.64	4.1%
1994	93.11	2.4%	2019	182.11	4.3%
			2020	189.94073	4.3%
			2021	198.10818	4.3%
			2022	206.62683	4.3%
			2023	215.51179	4.3%
			2024	224.77879	4.3%
			2025	234.44428	4.3%
			2026	244.52539	4.3%
			2027	255.03998	4.3%
			2028	266.0067	4.3%
			2029	277.44498	4.3%
			2030	289.37512	4.3%

Source: 1970-2019 DRI 25 Yr Trend: 0898 Forecast

Price Series to Adjust to $2001 Dollars from Nominal

2001	100%
2002	102%
2003	104%
2004	107%
2005	109%
2006	112%
2007	114%
2008	117%
2009	121%
2010	124%
2011	128%
2012	132%
2013	137%
2014	141%
2015	146%
2016	152%
2017	158%
2018	164%
2019	171%
2020	179%
2021	186%
2022	195%
2023	203%
2024	212%
2025	221%
2026	230%
2027	240%
2028	250%
2029	261%
2030	272%

CEC Monthly Natural Gas Retail Forecast

Month	Days per month	Year	2001 Dollars per Therm Residential	NonResidential
1	31	2005	0.663	0.579
2	28	2005	0.642	0.562
3	31	2005	0.628	0.549
4	30	2005	0.628	0.547
5	31	2005	0.646	0.557
6	30	2005	0.694	0.600
7	31	2005	0.692	0.595
8	31	2005	0.709	0.611
9	30	2005	0.694	0.600
10	31	2005	0.695	0.595
11	30	2005	0.676	0.575
12	31	2005	0.671	0.571
1	31	2006	0.664	0.580
2	28	2006	0.642	0.564
3	31	2006	0.629	0.551
4	30	2006	0.628	0.548
5	31	2006	0.646	0.559
6	30	2006	0.694	0.602
7	31	2006	0.691	0.597
8	31	2006	0.709	0.613
9	30	2006	0.694	0.602
10	31	2006	0.695	0.596
11	30	2006	0.676	0.576
12	31	2006	0.671	0.573
1	31	2007	0.674	0.589
2	28	2007	0.652	0.573
3	31	2007	0.638	0.560
4	30	2007	0.637	0.557
5	31	2007	0.656	0.569
6	30	2007	0.705	0.612
7	31	2007	0.702	0.607
8	31	2007	0.719	0.624
9	30	2007	0.704	0.612
10	31	2007	0.705	0.606
11	30	2007	0.686	0.586
12	31	2007	0.681	0.582
1	31	2008	0.674	0.592
2	28	2008	0.652	0.575
3	31	2008	0.639	0.562
4	30	2008	0.638	0.560
5	31	2008	0.657	0.572
6	30	2008	0.706	0.615
7	31	2008	0.703	0.611

8	31	2008	0.721	0.628
9	30	2008	0.705	0.616
10	31	2008	0.707	0.610
11	30	2008	0.687	0.589
12	31	2008	0.682	0.585
1	31	2009	0.679	0.597
2	28	2009	0.657	0.580
3	31	2009	0.643	0.567
4	30	2009	0.643	0.566
5	31	2009	0.661	0.577
6	30	2009	0.710	0.621
7	31	2009	0.708	0.617
8	31	2009	0.726	0.634
9	30	2009	0.710	0.622
10	31	2009	0.712	0.616
11	30	2009	0.692	0.595
12	31	2009	0.686	0.590
1	31	2010	0.682	0.600
2	28	2010	0.660	0.583
3	31	2010	0.646	0.571
4	30	2010	0.646	0.569
5	31	2010	0.664	0.580
6	30	2010	0.714	0.624
7	31	2010	0.711	0.621
8	31	2010	0.729	0.638
9	30	2010	0.714	0.626
10	31	2010	0.715	0.619
11	30	2010	0.695	0.598
12	31	2010	0.690	0.593
1	31	2011	0.684	0.603
2	28	2011	0.662	0.586
3	31	2011	0.648	0.573
4	30	2011	0.648	0.572
5	31	2011	0.666	0.584
6	30	2011	0.716	0.628
7	31	2011	0.714	0.625
8	31	2011	0.732	0.642
9	30	2011	0.716	0.629
10	31	2011	0.717	0.623
11	30	2011	0.697	0.602
12	31	2011	0.692	0.596
1	31	2012	0.688	0.608
2	28	2012	0.666	0.591
3	31	2012	0.652	0.579
4	30	2012	0.652	0.578
5	31	2012	0.671	0.590
6	30	2012	0.721	0.634
7	31	2012	0.720	0.632
8	31	2012	0.738	0.649
9	30	2012	0.721	0.636

10	31	2012	0.723	0.630
11	30	2012	0.703	0.608
12	31	2012	0.696	0.601
1	31	2013	0.695	0.615
2	28	2013	0.672	0.598
3	31	2013	0.658	0.585
4	30	2013	0.659	0.584
5	31	2013	0.678	0.597
6	30	2013	0.728	0.641
7	31	2013	0.727	0.639
8	31	2013	0.745	0.657
9	30	2013	0.728	0.644
10	31	2013	0.730	0.637
11	30	2013	0.710	0.615
12	31	2013	0.703	0.608
1	31	2014	0.699	0.620
2	28	2014	0.676	0.603
3	31	2014	0.663	0.590
4	30	2014	0.663	0.590
5	31	2014	0.683	0.603
6	30	2014	0.733	0.647
7	31	2014	0.733	0.646
8	31	2014	0.751	0.664
9	30	2014	0.734	0.650
10	31	2014	0.736	0.644
11	30	2014	0.715	0.621
12	31	2014	0.708	0.613
1	31	2015	0.704	0.626
2	28	2015	0.681	0.608
3	31	2015	0.667	0.596
4	30	2015	0.668	0.596
5	31	2015	0.687	0.609
6	30	2015	0.738	0.654
7	31	2015	0.738	0.653
8	31	2015	0.756	0.671
9	30	2015	0.739	0.657
10	31	2015	0.741	0.650
11	30	2015	0.720	0.628
12	31	2015	0.712	0.619
1	31	2016	0.709	0.632
2	28	2016	0.686	0.614
3	31	2016	0.672	0.602
4	30	2016	0.673	0.602
5	31	2016	0.693	0.615
6	30	2016	0.744	0.660
7	31	2016	0.743	0.660
8	31	2016	0.762	0.678
9	30	2016	0.745	0.664
10	31	2016	0.747	0.657
11	30	2016	0.725	0.634

12	31	2016	0.718	0.624
1	31	2017	0.714	0.638
2	28	2017	0.691	0.620
3	31	2017	0.677	0.607
4	30	2017	0.678	0.608
5	31	2017	0.698	0.621
6	30	2017	0.749	0.667
7	31	2017	0.749	0.667
8	31	2017	0.768	0.685
9	30	2017	0.750	0.671
10	31	2017	0.752	0.664
11	30	2017	0.731	0.640
12	31	2017	0.723	0.630
1	31	2018	0.719	0.643
2	28	2018	0.695	0.625
3	31	2018	0.681	0.613
4	30	2018	0.682	0.613
5	31	2018	0.702	0.627
6	30	2018	0.754	0.672
7	31	2018	0.754	0.673
8	31	2018	0.773	0.692
9	30	2018	0.755	0.677
10	31	2018	0.757	0.670
11	30	2018	0.736	0.646
12	31	2018	0.728	0.635
1	31	2019	0.724	0.648
2	28	2019	0.700	0.630
3	31	2019	0.686	0.618
4	30	2019	0.687	0.619
5	31	2019	0.707	0.632
6	30	2019	0.759	0.679
7	31	2019	0.760	0.680
8	31	2019	0.779	0.698
9	30	2019	0.761	0.683
10	31	2019	0.763	0.676
11	30	2019	0.741	0.652
12	31	2019	0.733	0.641
1	31	2020	0.728	0.653
2	28	2020	0.704	0.635
3	31	2020	0.690	0.623
4	30	2020	0.691	0.624
5	31	2020	0.712	0.637
6	30	2020	0.764	0.684
7	31	2020	0.764	0.685
8	31	2020	0.783	0.704
9	30	2020	0.765	0.689
10	31	2020	0.767	0.681
11	30	2020	0.746	0.657
12	31	2020	0.737	0.646
1	31	2021	0.733	0.658

2	28	2021	0.709	0.640
3	31	2021	0.694	0.628
4	30	2021	0.695	0.629
5	31	2021	0.716	0.643
6	30	2021	0.769	0.689
7	31	2021	0.769	0.691
8	31	2021	0.788	0.710
9	30	2021	0.770	0.694
10	31	2021	0.772	0.687
11	30	2021	0.750	0.662
12	31	2021	0.742	0.650
1	31	2022	0.738	0.663
2	28	2022	0.713	0.645
3	31	2022	0.699	0.633
4	30	2022	0.700	0.634
5	31	2022	0.721	0.648
6	30	2022	0.774	0.695
7	31	2022	0.774	0.697
8	31	2022	0.793	0.716
9	30	2022	0.775	0.700
10	31	2022	0.777	0.693
11	30	2022	0.755	0.668
12	31	2022	0.747	0.656
1	31	2023	0.743	0.668
2	28	2023	0.718	0.650
3	31	2023	0.703	0.638
4	30	2023	0.705	0.639
5	31	2023	0.725	0.654
6	30	2023	0.779	0.701
7	31	2023	0.779	0.703
8	31	2023	0.798	0.723
9	30	2023	0.780	0.706
10	31	2023	0.782	0.698
11	30	2023	0.760	0.674
12	31	2023	0.751	0.661
1	31	2024	0.747	0.674
2	28	2024	0.723	0.655
3	31	2024	0.708	0.643
4	30	2024	0.709	0.645
5	31	2024	0.730	0.659
6	30	2024	0.784	0.707
7	31	2024	0.784	0.709
8	31	2024	0.804	0.729
9	30	2024	0.785	0.712
10	31	2024	0.787	0.704
11	30	2024	0.765	0.679
12	31	2024	0.756	0.666
1	31	2025	0.752	0.679
2	28	2025	0.727	0.660
3	31	2025	0.713	0.649

4	30	2025	0.714	0.650
5	31	2025	0.735	0.665
6	30	2025	0.789	0.713
7	31	2025	0.789	0.716
8	31	2025	0.809	0.735
9	30	2025	0.790	0.719
10	31	2025	0.792	0.711
11	30	2025	0.770	0.685
12	31	2025	0.761	0.671
1	31	2026	0.757	0.684
2	28	2026	0.732	0.666
3	31	2026	0.717	0.654
4	30	2026	0.718	0.656
5	31	2026	0.740	0.671
6	30	2026	0.794	0.719
7	31	2026	0.794	0.722
8	31	2026	0.814	0.742
9	30	2026	0.795	0.725
10	31	2026	0.797	0.717
11	30	2026	0.775	0.691
12	31	2026	0.766	0.677
1	31	2027	0.762	0.690
2	28	2027	0.737	0.671
3	31	2027	0.722	0.660
4	30	2027	0.723	0.661
5	31	2027	0.744	0.677
6	30	2027	0.799	0.725
7	31	2027	0.799	0.729
8	31	2027	0.819	0.749
9	30	2027	0.801	0.732
10	31	2027	0.803	0.723
11	30	2027	0.780	0.697
12	31	2027	0.771	0.682
1	31	2028	0.767	0.696
2	28	2028	0.741	0.677
3	31	2028	0.727	0.665
4	30	2028	0.728	0.667
5	31	2028	0.749	0.683
6	30	2028	0.804	0.731
7	31	2028	0.805	0.735
8	31	2028	0.825	0.755
9	30	2028	0.806	0.738
10	31	2028	0.808	0.729
11	30	2028	0.785	0.703
12	31	2028	0.776	0.688
1	31	2029	0.772	0.701
2	28	2029	0.746	0.682
3	31	2029	0.731	0.671
4	30	2029	0.732	0.673
5	31	2029	0.754	0.689

6	30	2029	0.809	0.737
7	31	2029	0.810	0.742
8	31	2029	0.830	0.762
9	30	2029	0.811	0.745
10	31	2029	0.813	0.736
11	30	2029	0.790	0.709
12	31	2029	0.781	0.693
1	31	2030	0.777	0.707
2	28	2030	0.751	0.688
3	31	2030	0.736	0.676
4	30	2030	0.737	0.679
5	31	2030	0.759	0.695
6	30	2030	0.815	0.744
7	31	2030	0.815	0.748
8	31	2030	0.836	0.769
9	30	2030	0.816	0.751
10	31	2030	0.818	0.742
11	30	2030	0.795	0.715
12	31	2030	0.786	0.699
1	31	2031	0.782	0.713
2	28	2031	0.756	0.693
3	31	2031	0.741	0.682
4	30	2031	0.742	0.685
5	31	2031	0.764	0.701
6	30	2031	0.820	0.750
7	31	2031	0.820	0.755
8	31	2031	0.841	0.776
9	30	2031	0.822	0.758
10	31	2031	0.824	0.748
11	30	2031	0.800	0.721
12	31	2031	0.791	0.705
1	31	2032	0.787	0.718
2	28	2032	0.761	0.699
3	31	2032	0.746	0.688
4	30	2032	0.747	0.691
5	31	2032	0.769	0.707
6	30	2032	0.825	0.757
7	31	2032	0.826	0.762
8	31	2032	0.846	0.783
9	30	2032	0.827	0.765
10	31	2032	0.829	0.755
11	30	2032	0.805	0.728
12	31	2032	0.796	0.710
1	31	2033	0.792	0.724
2	28	2033	0.766	0.705
3	31	2033	0.750	0.694
4	30	2033	0.752	0.697
5	31	2033	0.774	0.713
6	30	2033	0.831	0.763
7	31	2033	0.831	0.769

8	31	2033	0.852	0.790
9	30	2033	0.832	0.771
10	31	2033	0.834	0.762
11	30	2033	0.811	0.734
12	31	2033	0.801	0.716
1	31	2034	0.797	0.730
2	28	2034	0.771	0.711
3	31	2034	0.755	0.700
4	30	2034	0.756	0.703
5	31	2034	0.779	0.720
6	30	2034	0.836	0.770
7	31	2034	0.836	0.776
8	31	2034	0.857	0.798
9	30	2034	0.838	0.778
10	31	2034	0.840	0.768
11	30	2034	0.816	0.740
12	31	2034	0.806	0.722
1	31	2035	0.802	0.736
2	28	2035	0.776	0.717
3	31	2035	0.760	0.706
4	30	2035	0.761	0.709
5	31	2035	0.784	0.726
6	30	2035	0.841	0.777
7	31	2035	0.842	0.783
8	31	2035	0.863	0.805
9	30	2035	0.843	0.785
10	31	2035	0.845	0.775
11	30	2035	0.821	0.747
12	31	2035	0.811	0.728

Table 1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

																									1998-
	1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2020**
Prices (1998 dollars per unit)																									
World Oil Price (dollars/bbl) 10/	18.71	12.10	17.13	21.19	20.06	20.18	20.28	20.39	20.49	20.59	20.70	20.79	20.90	21.00	21.10	21.21	21.31	21.42	21.53	21.63	21.74	21.84	21.95	22.04	2.8%
Gas Wellhead Price(dollars/mcf)11/	2.39	1.96	2.12	2.17	2.17	2.17	2.20	2.26	2.34	2.43	2.51	2.56	2.58	2.60	2.63	2.65	2.67	2.69	2.71	2.73	2.75	2.76	2.78	2.81	1.7%
Coal Minemouth Price(dollars/ton)	18.32	17.51	16.82	15.91	15.69	15.33	15.43	15.05	14.71	14.43	14.24	14.09	13.93	13.84	13.73	13.61	13.50	13.44	13.34	13.18	12.98	12.72	12.57	12.54	-1.5%
Average Electricity (cents / kwh)	6.9	6.7	6.6	6.6	6.5	6.3	6.2	6.2	6.1	6.1	6.1	6.0	5.9	6.0	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.8	5.8	-0.6%

10/ Average refiner acquisition cost for imported crude oil.

Btu = British thermal unit.

N/A = Not applicable.

Bbl = Barrel.

Mcf = thousand cubic feet.

Kwh = Kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 1997 and 1998 are model results and may differ slightly from official EIA data reports.

Sources: 1997 natural gas values: Energy Information Administration (EIA), Natural Gas Annual 1997, DOE/EIA-0131(97) (Washington, DC, October 1998). 1997 coal minemouth prices: EIA, Coal Industry Annual 1997, DOE/EIA-0584(97) (Washington, DC, December 1998). Other 1997 values: EIA, Annual Energy Review 1998, DOE/EIA-0384(98) (Washington, DC, July 1999). 1998 natural gas values: EIA, Natural Gas Monthly, DOE/EIA-0130(99/06) (Washington, DC, June 1999). 1998 petroleum values: EIA, Petroleum Supply Annual 1998, DOE/EIA-0340(98/1) (Washington, DC, June 1999). Other 1998 values: EIA, Annual Energy Review 1998, DOE/EIA-0384(98) (Washington, DC, July 1999) and EIA, Quarterly Coal Report, DOE/EIA-0121(99/1Q) (Washington, DC, August 1999). Projections: EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A.

K. Wholesale Propane Cost
From Petroleum Marketing Monthly, **Table 38**.
http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/pmm.html

L. Monthly Commodity Price Shape
From Petroleum Marketing Monthly, **Table 38**
http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/pmm.html

M. Monthly Class Load Shape
From Petroleum Marketing Monthly, **Table 49**.
http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/pmm.html